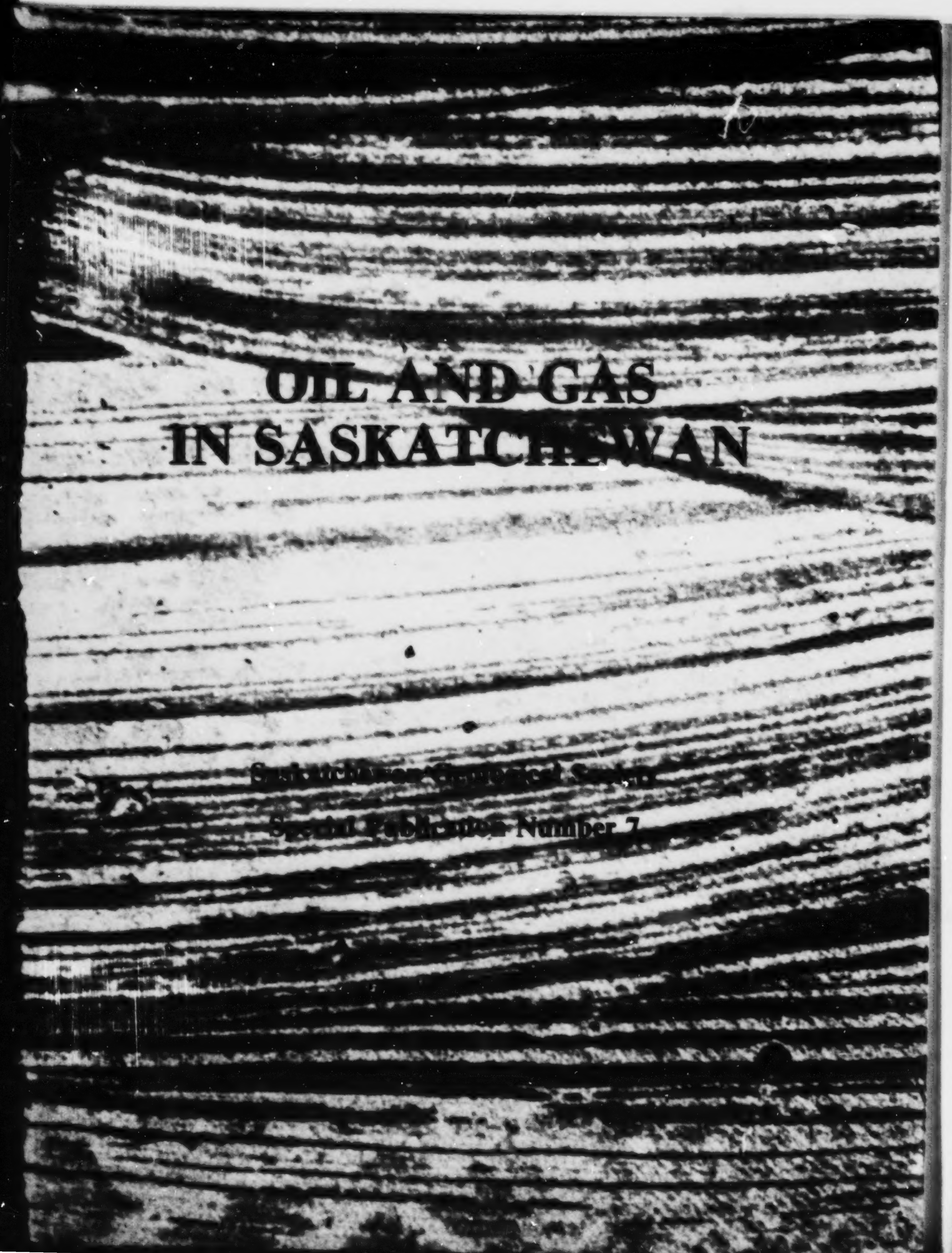

OIL AND GAS IN SASKATCHEWAN

Saskatchewan Geological Society

Special Publication Number 7

OIL AND GAS IN SASKATCHEWAN

Proceedings of a Symposium
Held in Regina, Saskatchewan
11 & 12 October 1984

EDITORS:
J. A. LORSONG and M. A. WILSON

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Cover:
Trough cross stratified sand from the Waseca formation,
Lower Cretaceous Mannville Group,
in Mobil Tangleflags A6-14-50-25W3
at 477 m depth.
Magnification ×3.

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FOREWORD

We are pleased to present a timely contribution to the petroleum geology of Saskatchewan. Amidst record land sales and drilling activity, we have assembled a collection of papers spanning Middle Devonian to Late Cretaceous strata in all of the major productive regions of Saskatchewan and adjoining areas. Although continued drilling and future study will modify many of the ideas presented here, the volume provides an overview of the state of the art in a region where ample exploration opportunities remain. The potential for substantial additions to reserves and increased production is highlighted by several significant discoveries since the Fourth International Williston Basin Symposium hosted by the Society two years ago.

The volume begins with a summary by Nisbet and Fowler of models for the origin of the economically most important structure in the Province, the Williston Basin. New data on potential Devonian reservoirs and caprocks in the Winnipegosis and Ashern Formations are presented in papers by Wilson and Lobdell. An overview of the Mississippian stratigraphy, sedimentology and hydrocarbon accumulations by Kent provides a regional framework for eight more detailed papers. These include a regional study of clastic source rocks and reservoirs in the Bakken Formation by Hornford as well as sedimentological, petrographic and petrophysical studies of carbonate reservoirs by Obelenus, LeFever and Anderson, Stoa *et al.*, Fischer *et al.* and Wegelin. In addition, Kent *et al.* and Akhurst report recent advances in understanding the relationships between pore geometry and reservoir quality in Mississippian carbonate reservoirs.

Christopher provides a regional overview of the stratigraphy and sedimentology of Lower Mesozoic reservoirs in the context of basin evolution, followed by Barchyn's paper on the recent Waskada play in Manitoba and its implications for Spearfish exploration in Saskatchewan. A recently released study by van Delinder provides a historical perspective on the evolution of models for oil migration and entrapment in the Cretaceous reservoirs of southern Saskatchewan. Widespread interest in commercial application of enhanced oil recovery technology has led to extensive research on the geology of heavy oil reservoirs in the Lloydminster area. A broad selection of new studies is presented in papers by Wilson, Groeneveld and Stasiuk, Smith *et al.*, MacEachern, Haidl, and Richardson and Vigrass. Simpson's detailed examination of the economic potential of other Cretaceous strata provides a regional framework for a Viking reservoir study by Tooth *et al.* and an evaluation of oil shales by Macauley. Griffin's discussion of a new log evaluation techique includes pertinent examples from various formations in Saskatchewan. The volume concludes with a brief summary of recent stratigraphic research by the Petroleum Geology Section of the Saskatchewan Geological Survey.

A volume of this scope cannot be produced in the brief period prior to the symposium without the cooperation of many companies and individuals. We are grateful to the authors, who have freely donated their time and expertise to produce quality papers within very strict time limits. We are indebted to the many Society members who have devoted untold hours to editing, proof-reading, layout and innumerable other tasks entailed in organisation of the symposium and production of the volume. We and the Society are especially grateful to the Saskatchewan Geological Survey (Department of Energy and Mines) and our corporate sponsors, without whom this endeavour would not have been possible. It is our hope that these efforts will contribute materially to continued success in the search for oil and gas in Saskatchewan.

The Editors

Regina, Saskatchewan
1 October 1984.

OIL AND GAS IN SASKATCHEWAN

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A REVIEW OF SOME MODELS FOR THE FORMATION OF THE WILLISTON BASIN.

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ABSTRACT

The Williston Basin appears to have been produced as a result of flexure of the lithosphere by loading. Subsidence may have been continuous throughout the Cambrian - early Cretaceous time period, to match a slowly increasing load, with eustatically controlled erosional breaks in the stratigraphic record. The Basin has probably had a gentle thermal history with a low and declining basal heat flow.

INTRODUCTION

A wide variety of geological processes lead to the formation of thick sedimentary deposits on continental crust. One class of deposits includes sediments laid down as a consequence of the extension or faulting of the basement; a second class forms in basins that result from flexure of the lithosphere in response to an imposed load. Amongst the first class of deposits are the thick marginal sediment sequences formed during and after rifting of a continent (for example, the Atlantic margins); basins formed during and after stretching of continental crust (for example, the North Sea, and one phase of the development of the Queen Charlotte Basin (Yorath and Hyndman, 1983); and basins formed in major fault grabens (e.g. the Rhine Graben). Most larger basins of this first class formed above stretched continental crust, and their subsidence record is characterised by initial rapid subsidence followed by an exponential slowing in the rate of subsidence. Early deposits are typically coarse clastic sediments laid down during a period of rapid infill; they are generally overlain by later finer-grained shallow-water deposits or carbonates as the rate of subsidence slows.

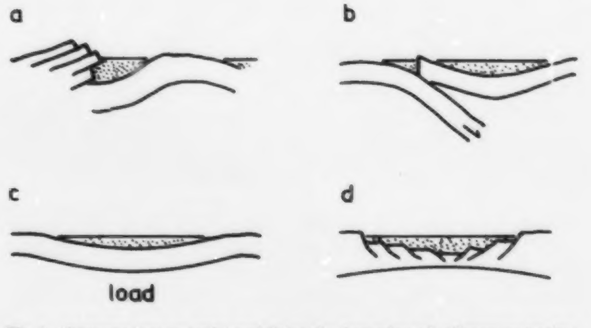

Fig. 1 - Cartoons (not to scale) explaining the formation of sedimentary basins:

Fig. 1a - Flexure by overthrust load, as in the Alberta Basin during the late Cretaceous and Tertiary.

Fig. 1b - Flexure above a subduction zone, as in part of the history of the Queen Charlotte Basin.

Fig. 1c - Flexure from load applied below (such as a cooling intrusive body, or a reaction change to denser material in the lithosphere)

Fig. 1d - Extensional basin, with thinned crust and lithosphere.

In contrast is the second class of deposits, produced by flexure of the lithosphere. The lithosphere is the uppermost cool and mechanically strong layer of the earth; it includes the crust and the cold top of the mantle. It is typically 150 km or more thick under continents. Since it is cold and strong, it can flex under an imposed load. An example of a flexural basin is the Alberta Basin in late Mesozoic and Tertiary time. As a result of the load imposed by thrusting of the Rocky Mountains (Beaumont, 1981), the Albertan crust has flexed downwards and deposition has taken place (Fig. 1a). Similarly, for part of its history the Queen Charlotte Basin has been flexed downwards (Fig. 1b) by a nearby subduction zone (Yorath and Hyndman, 1983). Another type of flexure occurs if a simple load is hung under the lithosphere (Fig. 1c). In contrast to stretching models (Fig. 1d), which demand a thinned lithosphere and an exponentially slowing rate of sedimentation, flexural basins do not necessarily have thin lithosphere and the subsidence history depends on the cause of flexure: the rate of subsidence does not necessarily slow exponentially, though it may do so.

Sleep, Nunn and Chen (1980) have investigated the formation of platform basins (those basins which form in the stable interiors of continents). For subaqueous deposition, the total thickness of sediment which can accumulate in a depression is given by the depth of the depression times a factor, F which is $(\varphi\,m-\varphi\,w)/(\varphi\,m-\varphi\,s)$, where φ is the density of mantle (m), water (w) and sediment (s). For basins such as the Williston Basin, the value of F is about 3 to 3.5. A basin filled with 5 km of sediment represents a subaqueous depression of the crust of approximately 1.5 km. The Williston Basin is thus a crustal depression of 1-2 km, continously infilled with sediment as it subsided which has amplified the subsidence caused by some tectonic process.

Constraints on the origin of the Williston Basin in pre-late Cretaceous time

Was the Williston Basin produced by the extension of its basement, or by flexure of the lithosphere, or by some other process?

Some critical evidence to help distinguish among these possibilities has been presented by Hajnal *et al.* (in press) and Fowler and Nisbet (in press): both geophysical and stratigraphic data appear to favour strongly a flexural model.

Hajnal *et al.* (in press) report the results of a set of seismic refraction experiments under the Williston Basin. They show that the continental crust is over 50 km thick in the central parts of the Basin in southern Saskatchewan. Other evidence showing thick crust was presented by Warren and Healy (1973) who inferred crustal thicknesses of up to 55 km in the southern Williston Basin. These observations almost completely exclude any possibility that the Basin formed by extension since extension would imply thin, not thick, continental crust. Fowler and Nisbet (in press) analyse the subsidence record of the Basin and show that the rate of subsidence appears not to be exponential: it does not slow with time. This conclusion strongly supports the seismological inference that the basin was not produced by extension of the basement.

What of the flexural models?

Since the record of mountain building or subduction in the vicinity of Williston is generally unimpressive, a model depending on a thrusted superimposed load is improbable. Only in the Cretaceous and Tertiary does the disturbing influence of the Rockies become apparent. We are thus left with models which assume loading from below.

Two such models have been proposed recently.

With regard to the first, Ahern and Mrkvicka (1984) show that the subsidence of the Basin can be explained by a load hung under the lithosphere or within it. Since the Basin has maintained a nearly constant centre of subsidence for most of its history, it can be modelled mathematically by assuming that a load hangs beneath a point at the centre of the Basin near Williston. The load, presumably a large geological body, would flex the lithosphere downwards.

The problem is: what is this load?

Ahern and Mrkvicak (1984) proposed that it may be a large intrusive body emplaced into the upper mantle during Cambrian times. Such a body would cool and contract slowly, becoming denser. Isostatic equilibration would then produce slow subsidence of the lithosphere: a 1-2 km deep flexure, enhanced by the load of sediment, would account for the Basin. A model depending in this way on thermal contraction would demand that subsidence in the later part of the Basin's history be slow.

Turning to the second model, Fowler and Nisbet (in press) have investigated the subsidence record of the Basin, and conclude that subsidence has been steady with exponential slowing during the Cambrian - early Cretaceous time interval. They further conclude that the major gaps in the Williston Basin's stratigraphy (Fig. 2) correlate closely with eustatic variations in sea-level. Most probably the Basin was filled with sediment to near sea-level throughout much of its Cambrian - early Cretaceous history so that small falls in sea-level led to erosion (amplified by the load factor, F, of about 3-3.5). A sustained 100 m drop in sea-level might have produced up to 350 m of erosion (the sea-level fall caused by the Permo-Triassic glaciation of the southern continents may have been much greater). Between these erosional events, the subsidence rates appear to have been steady (Fig. 3). Fowler and Nisbet (in press) suggest that this steady subsidence is best explained by a model which involves progressive metamorphic reactions in the uppermost mantle and lower crust. If, for example, a gabbro layer at 50 km (such as would be produced by underplating in a major flood basalt event comparable to the Karoo event in Southern Africa) cools and transforms to eclogite over a time period of the order of 10^9 years, then an apparently near-steady subsidence would result over much of the 400 my of the Basin's pre-late Cretaceous record. Seismological evidence in support of this model comes from the detection of a high velocity layer, possibly eclogite, in the uppermost mantle beneath the Basin, (Hajnal *et al.*, in press).

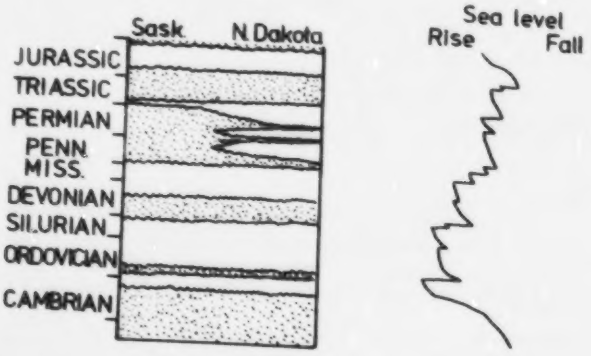

Fig. 2 - Stratigraphic record of the Williston Basin (erosional gaps stippled). Note that each erosional gap correlates with an episode of low sea-level, as shown by the Vail sea-level curve. During a regressive period, erosion cuts into the stratigraphic record since, if isostatic equilibrium is maintained, 100 m of regression will remove up to 300-350 m of sediment. As sea-level rises again, sedimentation will resume when the sea floods the residual topography. Throughout the time period Cambrian-early Cretaceous, subsidence was probably steady so that even if sea-level maintained a low stand the land surface would eventually have dropped below sea-level.

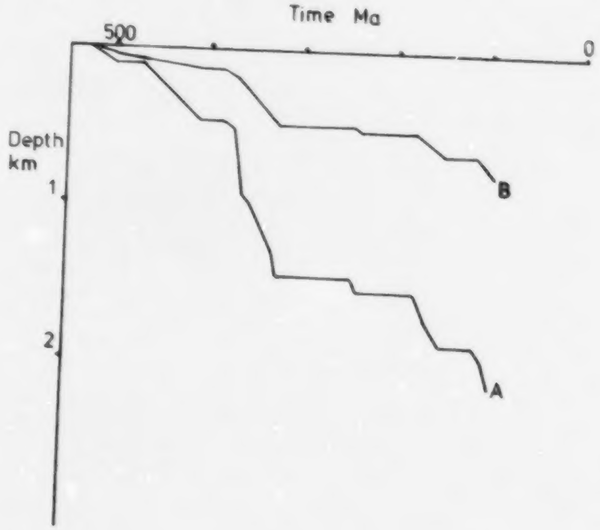

Fig. 3 - Typical infill record from wells in southern Saskatchewan (curve A). Note that periods of non-deposition alternate with episodes of steady subsidence. Curve B is a typical subsidence curve, constructed by removing the effect of the sediment infill in the Basin and by estimating for water depths as recorded in sedimentary facies. If no sediment had been laid down, the Williston Basin in this part of southern Saskatchewan would have been about 700 m deep by mid-Cretaceous time; with sediment, the succession is over 2 km thick.

These theories pertain to the history of the Basin prior to the onset of thrusting in the Rockies and the associated flexure. Since then, the Basin's history has been complicated by, in addition to tectonism, such factors as Quaternary glaciation and the current low stand of sea-level.

IMPLICATIONS

For most of its history, the subsidence of the Williston Basin can be explained simply as the effect of adding steadily to a load in the lithosphere, with the stratigraphic breaks simply being consequences of eustatic changes. Fine details of sediment facies changes and thickness variation can be ascribed to factors such as the varying distribution of the load, local accidents of erosion and deposition (which would themselves influence the flexural history of the lithosphere) and the eustatic history. The explanation is perhaps over-simple, but it is effective. Also, it may have some economic significance, as it helps provide a model for the regional heat flow. In a stretching basin, initial high heat flow slowly decreases. In a flexural basin, the basement heat flow varies less although it may be elevated by early sub-crustal intrusion. In the Williston Basin heat flow has probably been low (Jessop and Lewis, 1976) for much of the Phanerozoic, with temperatures in the sediments largely controlled by circulating groundwater (Margara, 1976). This regime would have a major impact on the maturity of the oils within the Basin.

ACKNOWLEDGMENTS

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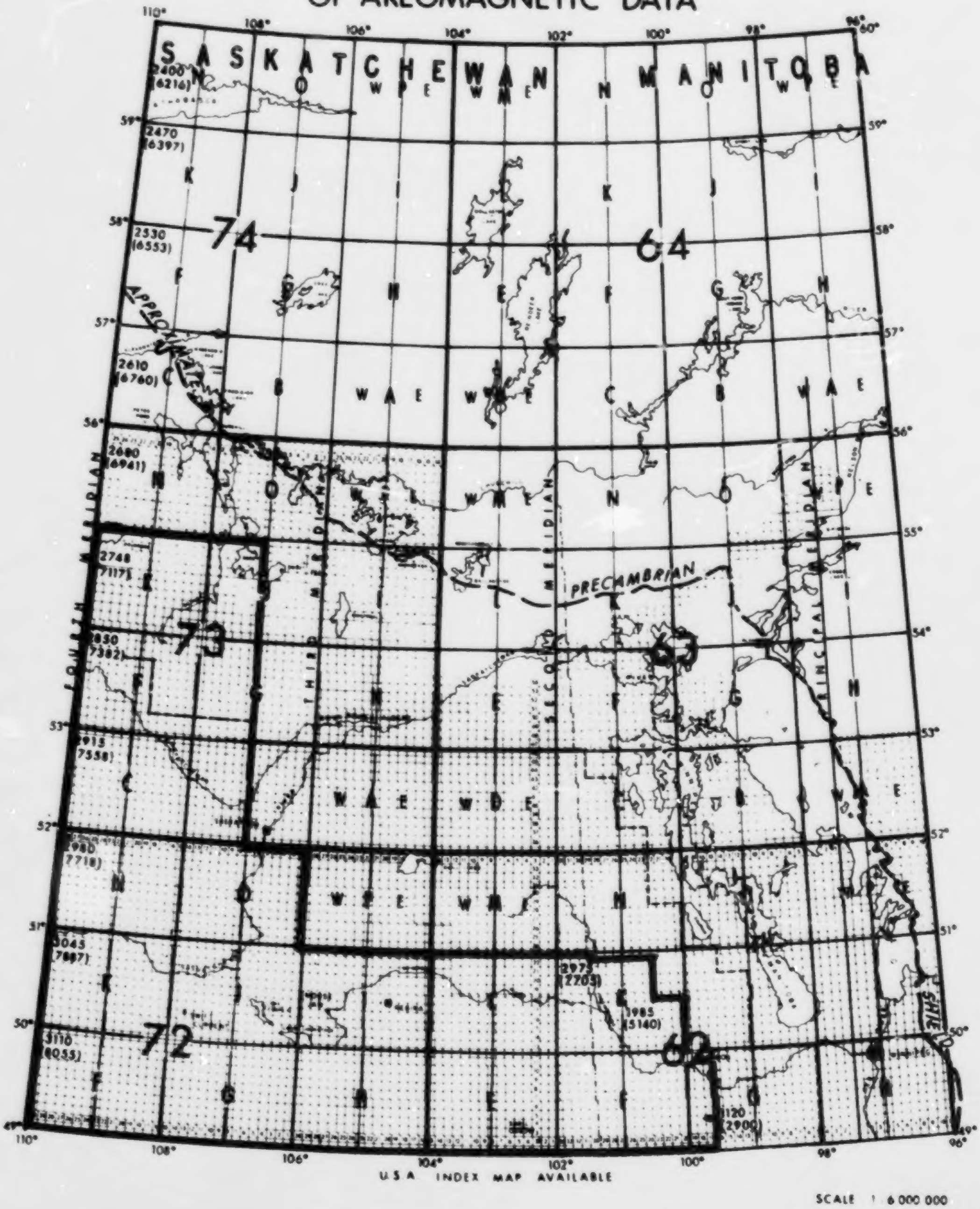
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AGE AND DEPOSITIONAL HISTORY OF THE MIDDLE DEVONIAN ASHERN FORMATION IN THE WILLISTON BASIN, SASKATCHEWAN AND NORTH DAKOTA

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ABSTRACT

The Ashern Formation in North Dakota represents the base of the initial Devonian transgression. It unconformably overlies the Silurian Interlake Formation and underlies, generally paraconformably, the Middle Devonian Winnipegosis Formation. The Ashern attains a maximum thickness of 55 m (180 ft) in northwestern North Dakota.

Following previous stratigraphic usage in Saskatchewan, the Ashern in North Dakota is divided into a lower red member (geographicaly restricted) and an upper gray member. Where the red member is absent the gray member directly overlies the Interlake Formation. Both members consist of an argillaceous microcrystalline dolostone containing minor quartz silt. Anhydrite is present in both members but is much more abundant in the lower red member, where it frequently forms beds or layers of nodules. In the gray member calcispheres are observed in approximately 10% of the thin sections studied. Desiccation features are uncommon; they occur occasionally in the red member.

The depositional model which seems most appropriate for the lower red member is that of a coastal sabkha; for the upper gray member, a restricted marine model seems to fit best. The paucity of desiccation features in the red member may be accounted for by a rising sea level, with a concomitant rising water table, during the time of deposition of the red member.

INTRODUCTION

The Ashern Formation was named by Baillie (1951) for "the brick-red to greyish-orange dolostone strata" which underlie the Winnipegosis and Elm Point Formations (Middle Devonian) of the Interlake area of Manitoba. Baillie subsequently (1953, 1955) extended the Ashern into the subsurface of Manitoba, Saskatchewan, and North Dakota. The Ashern marks the base of the Devonian transgression (Kaskaskia Sequence of Sloss, 1963) southeast of the Meadow Lake Escarpment, and unconformably overlies Silurian and Upper Ordovician rocks.

In North Dakota, the Ashern is composed almost entirely of argillaceous microcrystalline dolostone. Anhydrite is locally abundant, forming beds or layers of nodules, particularly in the red member. Quartz silt, chert, hematite, pyrite, and halite are minor constituents (Lobdell, 1984). In the subsurface of Manitoba and Saskatchewan, the Ashern has been described as consisting of dolostones and shales (Baillie, 1953, 1955; Walker, 1957; Jones, 1965; Norris, Uyeno, and McCabe, 1982). The writer suspects that, with further investigation, the Ashern in these latter areas will prove to be more dolostone and less shale.

Sedimentary structures are not common in the Ashern, as Kendal (1975) noted; however, near the base of the formation there are a few zones of brecciation and rip-up clasts. Cryptalgal laminae, stylolites, and microstylolites are present, as well as dish structures in one core.

GEOLOGIC SETTING

Throughout much of its history, the Williston Basin has been connected to the open ocean in a westerly to southwesterly direction. During Middle Devonian time, however, the sea transgressed from the northwest and the Williston Basin became a sub-basin of the Elk Point Basin. Why this shift took place is unknown, but Gerhard *et al.* (1982), suggested that it may have been related to uplift of the Transcontinental Arch, which, in turn, may have been linked to the Antler or Acadian orogenies.

During the Late Silurian, the sea withdrew from the Williston Basin, as it did from much of the craton, and a lengthy period of weathering and erosion ensued. This major regional unconformity marks the boundary between the Tippecanoe and Kaskaskia Sequences.

The Elk Point Basin is distinguished from the earlier Williston Basin by its spread to the northwest and by a shifting of the depocenter from northwestern North Dakota to southern Saskatchewan and east-central Alberta (Norris *et al.*, 1982). (The isopach map of the Ashern. (Fig. 1), however, clearly shows a depocenter in northwestern North Dakota.)

One of the most important features in the Elk Point Basin is the Meadow Lake Escarpment (Fig. 2). Northwest of the Meadow Lake Escarpment the pre-Ashern Lower Elk Point subgroup is about 300 m (1000 ft) thick; southeast of the escarpment of the Ashern rests on Silurian and Upper Ordovician carbonates (Van Hees, 1958). Silurian, Ordovician, and some Cambrian strata have been removed by erosion northwest of the escarpment; there, the Lower Elk Point subgroup rests directly on the Deadwood Formation (Fuzesy, 1980). Although Kesling and Takagi (1961) felt that the escarpment was erosional, Fuzesy (1980) stated that it was fault-controlled, and Van Hees (1958) noted that it was a westward extension of the boundary between the Precambrian Churchill and Superior Provinces. Stratigraphic relationships in the vicinity of the Meadow Lake Escarpment are discussed more fully below.

The Swift Current Platform in southwestern Saskatchewan which was also emergent during Ashern time. There, Winnipegosis rocks rest directly on Lower Paleozoic carbonates (Grayston, Sherwin, and Allan, 1964). Other prominent structures were the Nesson and Cedar Creek Anticlines. The isopach map (Fig. 1) of the Ashern shows that the Cedar Creek Anticline was emergent during Ashern time, and the Nesson was poorly defined.

According to a recent Devonian paleogeographic reconstruction (Heckel and Witzke, 1979), the Elk Point Basin lay between 10°S and 20°S latitude during the Middle Devonian. This places the Elk Point Basin in the hot, arid, tradewind belt. Because this was in the southern hemisphere, the trade winds blew from the east, directly off the Canadian Shield (Heckel and Witzke, 1979).

STRATIGRAPHIC RELATIONSHIPS AND AGE ASSIGNMENT

Because of the almost total lack of fossils, the age of the Ashern Formation can not be determined directly. As recently as 1982, Norris *et al.* (p. 17) referred to the age of the Ashern as "an unsettled problem." The Ashern has been considered Silurian, Early Devonian, and/or Middle Devonian by various workers; however, consideration of stratigraphic relationships in central and northern Saskatchewan and Alberta and southern Northwest Territories can provide a reasonable solution to the problem.

The Ashern is everywhere overlain by the Winnipegosis and Elm Point Formations. These units contain the guide fossils *Desquamatia (Variatrypa) arctica* (Warren) and *Stringocephalus* sp., indicating a Late Eifelian and/or Early Givetian (Middle Devonian) age. This upper limit on the age of the Ashern has never been questioned; it is the lower limit which has been the subject of much speculation.

Southeast of the Meadow Lake Escarpment, the Ashern is underlain by Upper Ordovician and Silurian strata. Because the top of these strata marks a regional unconformity, it is not known how much of the record was lost during this time of nondeposition and erosion. Additionally, the fauna of the Interlake Formation is not adequately described and dated. Therefore, if the Ashern, is to be successfully dated, the formations northwest of the Meadow Lake Escarpment must be examined.

The Ashern Formation, as a formal stratigraphic unit, is not extended north of the Meadow Lake Escarpment. It has proven more convenient to map Ashern correlatives with the Meadow Lake Formation (Fuzesy, 1980) and with the Contact Rapids Formation (Sherwin, 1962). Deposition was, however, continuous across the Meadow Lake Escarpment during Ashern time: "Mudstones and argillaceous dolomites . . . constitute the Ashern Formation southeast of the Meadow Lake Escarpment and to the northwest the uppermost part of the Contact Rapids Formation in Alberta and the upper part of the Meadow Lake Formation (new name) in Saskatchewan" (Fuzesy, 1980, p. 1). Indeed, Van Hees (1956) showed the Ashern Formation extending across the region, that he later (1958) called the Meadow Lake Escarpment, into east-central Alberta. The characteristic gamma ray "signature" may be clearly seen on the logs reproduced in Van Hees' cross-section and is also evident in Sherwin's (1962, Fig. 3) and Fuzesy's (1980, Fig. 1) cross-sections. Lithologic descriptions for the upper Meadow Lake by Fuzesy (1980) and for the upper Contact Rapids by Sherwin (1962) are very similar to Ashern lithologic descriptions from this area as given by Walker (1956) and Kendall (1975).

Northeast of the Meadow Lake Escarpment lies the Central Alberta sub-basin (terminology from Norris *et al.*, 1982; see Fig. 2); almost 300 m (1000 ft) of pre-Ashern Devonian sediments were deposited in this sub-basin. These sediments consist of a basal red bed, overlain by two thick salts (the Lotsberg and Cold Lake Formations) separated by a thin limestone (The Ernestina Lake Formation) and topped by the

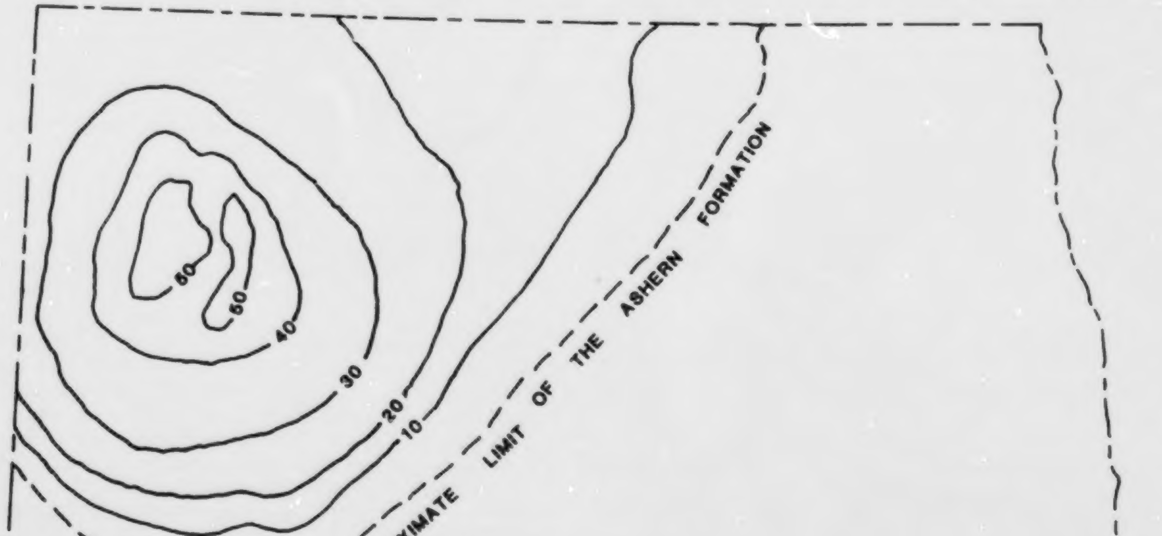

Fig. 1 - Isopach map of the Ashern Formation in North Dakota. Contour interval is 10 m.

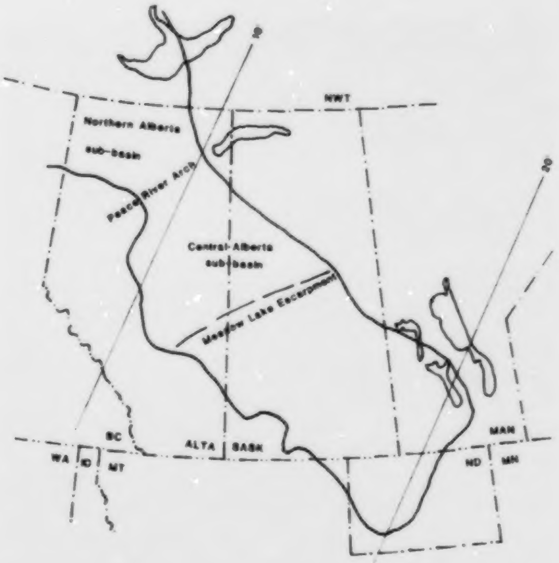
NWT
Northern Alberta sub-basin
Peace River Arch
Central Alberta sub-basin
Meadow Lake Escarpment
10
20
BC
ALTA
SASK
MAN
WA
ID
MT
ND
MN

Fig. 2 - Map of the Elk Point Basin. Modified after Grayston *et al.* (1964). Lines of paleolatitude from Heckel and Witzke (1979).

Contact Rapids Formation, which is composed of argillaceous dolostone and dolomitic shale (Sherwin, 1962). With the exception of the Ernestina Lake Formation, these units are barren of fossils. The Ernestina Lake contains one species of ostracode (*Welleria meadowlakensis)* which is locally abundant.

The Northern Alberta sub-basin lies north of the Peace River Arch (Fig. 2). Here, too, a substantial thickness of pre-Winnipegosis sediments was deposited. Overlying the Precambrian basement is the La Loche Formation, a thin granite wash. Above the La Loche lies the Fitzgerald Formation, a fossiliferous limestone; which in turn is overlain by salt of the Cold Lake Formation. It should be noted that the Cold Lake salt of the Northern Alberta sub-basin is not contiguous with that of the Central Alberta sub-basin. Rather, both salts grade laterally into a series of redbeds over the Peace River Arch; they are thought to be the same unit due to their lateral continuity with the redbeds and their stratigraphic position immediately below a continuous unit. Above the Cold Lake is the Chinchaga Formation, which grades southward into the Contact Rapids Formation (Rice, 1967). These relationships are shown schematically in Figure 3.

It is the Fitzgerald Formation which is of interest here. A sparse fauna consisting of a coral, several species of brachiopods, and a number of ostracode species is know from the lower part of this unit. Several forms are exclusively Eifelian (lower Middle Devonain) species. From the upper part of the Fitzgerald Formation only the ostracode *W. meadowlakensis* is recorded. Thus, the lower limit on the age of this ostracode, and therefore on the age of the Fitzgerlad and Ernestina Lake Formations, would seem to be Eifelian. This means that in the Central Alberta sub-basin, strata equivalent to the Ashern Formation are limited below by the Eifelian Ernestina Lake Formation and above by the Late Eifelian to Early Givetian Winnipegosis Formation. Therefore, the Ashern Formation also must be Eifelian in age.

DEPOSITIONAL ENVIRONMENTS

There are too few primary features of the Ashern sediments to enable environmental interpretations. Most of the Ashern Formation consists of a featureless microcrystalline dolostone; much of the remainder is identical except for the presence of faint, discontinuous laminae. Nonetheless, some tentative con-

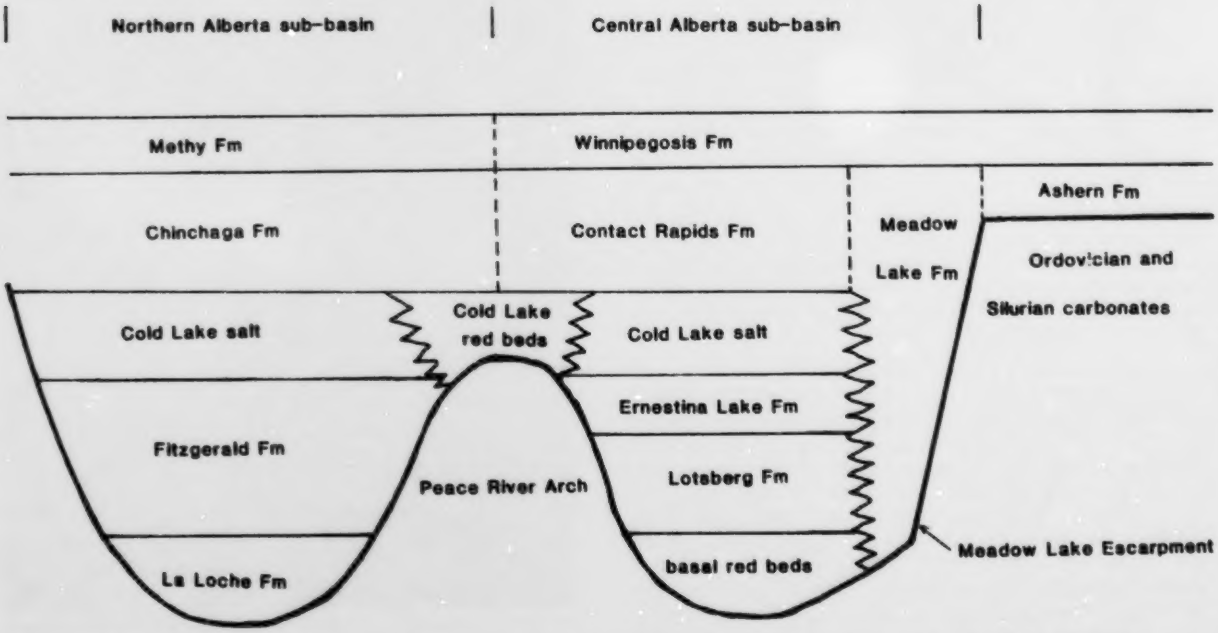
Northern Alberta sub-basin
Central Alberta sub-basin
Methy Fm
Winnipegosis Fm
Ashern Fm
Chinchaga Fm
Contact Rapids Fm
Meadow Lake Fm
Ordovician and Silurian carbonates
Cold Lake salt
Cold Lake red beds
Cold Lake salt
Ernestina Lake Fm
Fitzgerald Fm
Peace River Arch
Lotsberg Fm
La Loche Fm
basal red beds
Meadow Lake Escarpment

Fig. 3 - Schematic stratigraphic cross-section in the vicinity of the Meadow Lake Escarpment and farther north. Modified from Rice (1967) and Fuzesy (1980).

clusions as to the depositional environments of the Ashern are submitted.

PRIMARY SEDIMENTS

The most abundant primary sediment in the Ashern Formation is the lime mud that is precursor to the microcrystalline dolomite that presently comprises more than 80% by weight of the rock. There is consideralbe uncertainty as to the origin of the lime mud, and some authors (*e.g.*, Wilson, 1975) assert that most, if not all, is organically derived. It has been, established, however, that it is possible to precipitate calcium carbonate out of sea water at salinities exceeding 72 ppt (Heckel, 1972). The almost total lack of fossils in the Ashern would preclude a shell-organic origin for the carbonate mud, although bacterially catalyzed or even algal carbonate production is by no means out of the question. If the climate during Ashern time was hot and dry, as postulated by Heckel and Witzke (1979), and if circulation in the basin was indeed restricted, then salinities could have increased to the point that direct precipitation of calcium carbonate from sea water resulted. In modern settings, inorganic precipitation has been hypothesized to be the agent of much of the carbonate sediments in portions of the Red Sea and Persian Gulf (Milliman, Ross, and Ku, 1969; Milliman, 1974). Direct precipitation of calcium carbonate from sea water does not, therefore, seem an unreasonable mechanism for the source of the Ashern carbonates.

The other primary sediments are clays and quartz silt. Quartz silt amounts to 1% or 2% of the rock, and clays average perhaps 18%. The winds are quite capable of transporting these sizes for long distances (Wilson, 1975), and is probably repsonsible for the bulk of the terrigenous material in the Ashern.

LOWER RED MEMBER

Microcrystalline dolomite (Fig. 4) and minor quartz silt are the components of both members. The basal red member is distinguished by colour, nodular anhydrite (Fig. 5 , 6) and occasional desiccation features (Lobdell, 1984). The red colour of the beds suggests, but is not diagnostic of, subaerial origin (Wilson, 1975). Nodular anhydrite has not yet been reported from a subaqueous environment; the combination of features described above is strongly indicative of subaerial, rather than subaqueous, deposition (*cf.* Shinn, 1983).

Coastal sabkha sequences are characterized by microcrystalline dolomite, nodular and enterolithic anhydrite, and gypsum "mush." Desiccation features and erosion surfaces are also common. Good summaries of sabhka sedimentology are given by Shearman (1978), Kendall (1979), and Butler, Harris, and Kendall (1982).

Studies of modern coastal sabkhas deal, of necessity, with regressive successions (i.e., prograding sabkhas). The Ashern, however, was deposited under transgressive conditions and does not show progradational stratigraphic relationships. Modern sabkhas are known to build rapidly, geologically speaking; progradation rates of a mile per thousand years have been reported (Shearman, 1978). This implies that, if the Ashern sabkha built up (rather than out) for 15 to 18 meters (50 to 60 feet) and was eventually "drowned", the rate of marine flooding of Ashern environments must have been quite rapid also. The isopach map of the Ashern (Fig. 1) indicates basin subsidence during this time. It is possible that the entire basin was initially slightly below sea level, but that the

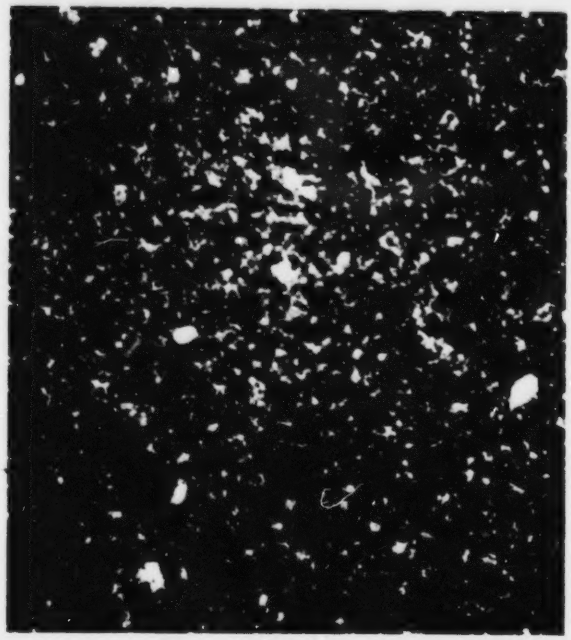

Fig. 4 - Photomicrograph of microcrystalline dolomite. Larger, light coloured grains are quartz silt. Width of photograph is about 2 mm (0.08 in). The sample is from Blackwood and Nichols No. 1 Gilman and Lang, NE SE Sec. 15, T. 140 N., R. 105 W., Golden Valley County, North Dakota, 3355.5 m (11009 ft).

Fig. 5 - Nodular anhydrite in red dolostone matrix. Bar is 1 cm (0.4 in). Amerada No. 1 Wollan, NW NW Sec. 15, T. 152 N., R. 96 W., Williams County, North Dakota, 3724.4 m (12219 ft).

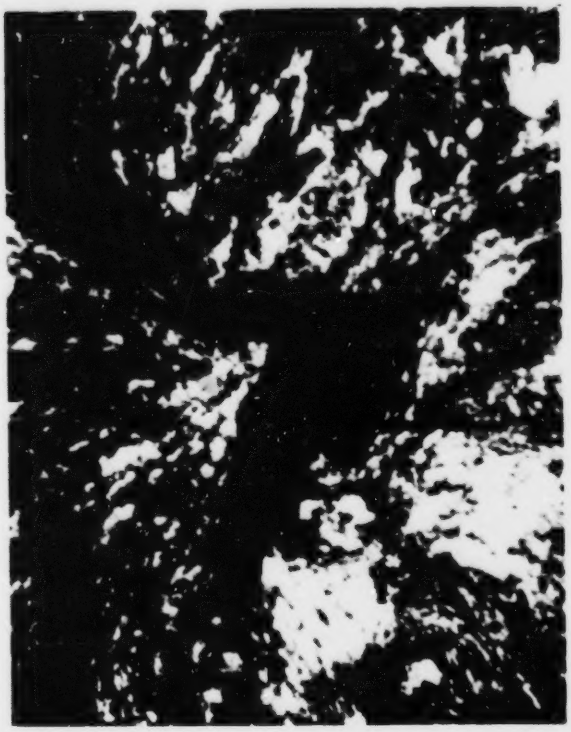

Fig. 6 - Photomicrograph of felted texture in anhydrite nodule. Dark area in middle is inclusion of dolomicrite. Width of photograph is about 4 mm (0.16 in). Amerada No. 9 North Dakota "A" Unit, SE SW Sec. 16, T. 156 N., R. 95 W., Williams County, North Dakota, 3580.3 m (11746.5 ft).

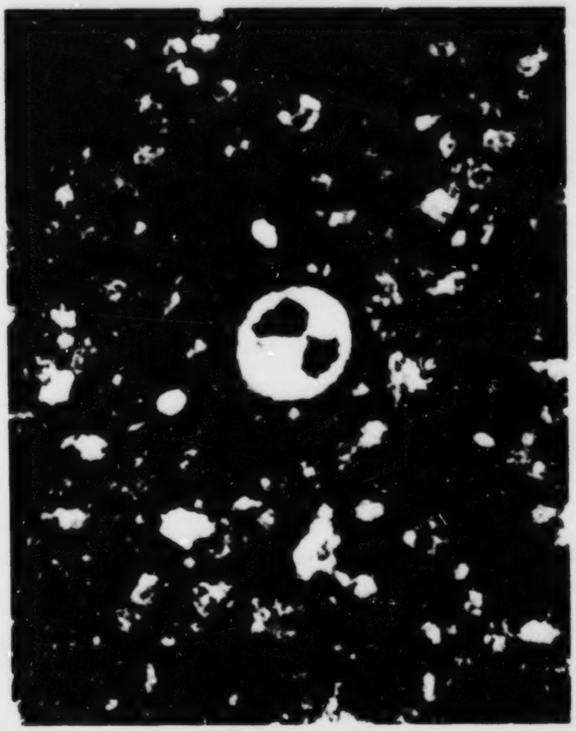

Fig. 7 - Photomicrograph of a calcisphere composed of equant calcite. Width of area in photograph is about 1 mm (0.04 in). Socony-Vacuum No. 1 Dvorak, SE NE Sec. 6, T. 141 N., R. 94 W., Dunn Country, North Dakota, 3414.4 m (11202 ft).

Meadow Lake Escarpment acted as a levee to prevent marine flooding. When this barrier was finally breached, the basin could have filled rapidly, leaving a weakly positive central area emergent for the time necessary to form the sabkha sediments of the lower red member before finally being flooded. As sea level rose, the water table under the sabkha undoubtedly rose also. This flooding of former erosion surfaces probably destroyed any record of them, and may help to explain the paucity of desiccation features in the red member of the Ashern.

UPPER GRAY MEMBER

The gray member of the Ashern is an argillaceous microcrystalline dolostone, medium to dark gray, with occasional wispy, discontinuous laminae and rare shale partings. Calcispheres (Fig. 7) are found in perhaps 10% of the thin sections of the gray member studied.

The gray colour clearly implies a reducing environment. Iron is present almost exclusively as pyrite, only rarely as hematite. The abundance of pyrite probably contributes to the dark colour of the dolostone. If Wilson (1975) is correct in the assertion that a dark gray carbonate reflects conditions that are more reducing than normal, then the gray member of the Ashern, particularly in the basin center, must have been deposited under poorly oxygenated conditions.

Calcispheres are of unknown affinity but are currently though to be reproductive bodies of green algae. They are considered by some workers to be virtually diagnostic of restricted circulation and/or lagoonal environments (Wray, 1977; Scholle, 1978).

Therefore, the gray member of the Ashern is interpreted to have been deposited in a restricted embayment within the Elk Point Basin. The Meadow Lake Escarpment acted as a sill, or a sill could have been located farther north, at the Peace River Arch, for instance. Wherever it was located, it was deep enough to permit a two-way flow, incoming normal marine water at the surface and denser, somewhat hypersaline water returning to the open marine realm along the bottom. It seems plausible that this occurred because, with minor exceptions, evaporite minerals were not deposited in the basin at this time.

The homogeneity of the sediments, or the lack of primary bedding or lamination, may be accounted for in at least two ways. First, the basin may have been shallow enough so that storm waves would periodically churn up the bottom sediments. Second, primary bedding may have been disturbed through bioturbation. The total lack of a preserved biota does not rule out bioturbation; Rhoads and Morse (1971) have shown that, in general, soft-bodied organisms have a greater tolerance for low dissolved oxygen than do shelled animals.

There are two anomalies that need to be considered in order to complete an environmental reconstruction of the Ashern Formation. The first is the presence of two bodies of halite that are centered in western Mountrail County and northeastern Williams County, North Dakota. These rock salts (Fig. 8) have a combined area in the order of 2500 km^2 (1000 mi^2)

and attain a maximum thickness of 18 m (60 ft). One core, from a well on the periphery of one of these areas, penetrates the salt for only 0.4 m (1.5 ft). The halite consists of euhedral cyrstals, the maximum dimenson of which is 2.5 cm (1 in), interbedded with carbonate mud.

The salt bodies are near the site of maximum subsidence of the Ashern basin and it seems quite possible that they reflect a small depression within the larger basin. This depression would have had the effect of trapping the denser brine that would normally flow along the bottom out of the basin, and as these brines became more concentrated, halite could have been precipitated (*cf.* Heckel, 1972). The absence of sulfate minerals does not preclude this model, since these minerals are deposited from well oxygenated waters (Schreiber, Roth, and Helman, 1982).

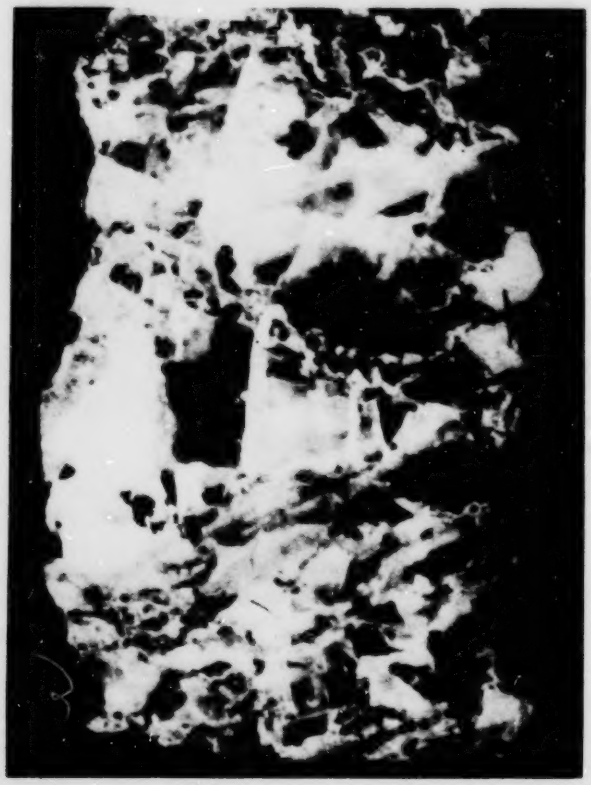

Fig. 8 - Core slab of large euhedral halite crystals. Width of slab is about 10 cm (4 in). Amerada Beaver Lodge Devonian Unit H310, SW NE Sec. 31, T. 156 N., R. 31 W., Williams County, North Dakota, 3531.1 m (11585 ft).

The second anomalous sedimentary deposit is cored in a well in central Golden Valley County, North Dakota. The core contains an abundance, up to 30%, of well-rounded, frosted, very fine to very coarse quartz sand, 0.6 to 1.0 m thick, directly above the Interlake Formation. Such deposits have been reported in the literature. "Zones of rounded, frosted, rather large quartz grains are known from many sections and probably represent coastal dune and beach sands reworked in the shallow marine environment" (Wilson, 1975, p. 91). This well is located near the limits of Ashern deposition, and Wilson's explanation seems entirely reasonable.

DIAGENESIS

Both the red and the gray members have been thoroughly dolomitized, but they must be considered separately because different dolomitization models are applicable. The most appropriate model for the dolomitization of the red member is "evaporative pumping," which has been summarized recently by McKenzie, Hsu, and Schneider (1980).

Much of the anhydrite found in the sabkha environment is a replacement of gypsum, though evidence for such replacement is commonly lacking. Anhydrite nodules grow displacively in the sediment and display a felted texture in thin section (Kinsman, 1969; Butler, 1969; Butler *et al.*, 1982).

Dolomitization also took place in the gray member, though not in a sabkha setting. A restricted lagoon or embayment in a hot, dry climate is postulated for the depositional environment of the gray member. As relatively rapid evaporation took place, and given poor circulation, salinities rose to the point that calcium carbonate precipitated, raising the Mg^{2+}/Ca^{2+} ratio. Denser hypersaline water sank to the bottom and flowed out of the embayment over the sill that was covered by enough water to permit two-way flow. Thus, the magnesium-enriched brine flowed through surficial bottom sediments, dolomitizing them in a process similar to seepage refluxion (Adams and Rhodes, 1960). If so dolomitization probably occurred late in the history of the Ashern basin, after deposition of most or all of the lime mud precursor sediment; dolomitizing fluids probably penetrated to only shallow depths within the bottom sediments (*cf.* Kent, Akhurst and Burton, this volume).

SUMMARY

The Ashern Formation is the basal unit of the Middle Devonian transgression in the Elk Point Basin southeast of the Meadow Lake Escarpment. Stratigraphic relationships and faunal evidence in the vicinity of the Escarpment and farther north demonstrate an Eifelian (early Middle Devonian) age for the Ashern.

The argillaceous microcrystalline dolostones of the Ashern were laid down in two major depositional settings. Sometime during the Eifelian, marine waters transgressed the Meadow Lake Escarpment and crossed southeastward into Saskatchewan and North Dakota. It is possible that the basin floor was below sea level, causing relatively rapid filling with water. There was, however, a linear positive area (a peninsula, island or archipelago) that remained emergent during the initial stages of transgression. On this positive area, the lower red member was deposited in a supratidal sabkha under conditions of rising sea level. Sedimentation kept pace with sea level rise for some time, building up to a thickness of as much as 18 m (60 ft). With continued rise of sea level, the entire area became a restricted embayment in which gray carbonates of the upper member were deposited under hypersaline reducing, subtidal conditions. Direct precipitation of carbonates ceased when the restriction yielded to circulation of normal marine waters. The contact between the Ashern and the overlying Winnipegosis Formation marks this change in sedimentological regimes. The Ashern represents the initial transgressive phase of the Kaskaskia transgressive - regressive episode which reached its maximum with the Winnipegosis Formation.

ACKNOWLEDGEMENTS

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THE WINNIPEGOSIS FORMATION OF SOUTH-CENTRAL SASKATCHEWAN

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INTRODUCTION

The Middle Devonian Winnipegosis Formation in central Saskatchewan is a highly dolomitized carbonate sequence composed of a platform (Lower Member) upon which rest numerous small mounds (Upper Member). In addition, the mounds are separated from each other by a thin carbonate mud deposit (Ratner Member). The Lower Member is a regionally dolomitized, mottled, argillaceous, organic-rich unit. It ranges in thickness from 6 to 15.5 metres. The top of the Lower Member was defined by Jones (1965) as the top of a thin, regionally developed argillaceous interval.

The Upper Member, which is the focus of this study, consists of dolomitized carbonate 'mounds' that are up to 105 metres thick. Wardlaw and Reinson (1971) and Streeton (1971) considered that the mounds are extensive carbonate banks, bounded by low angle slopes. Gendzwill (1978) concluded that the mounds are much smaller than originally interpreted and have steeper sides and flat tops. Further investigation has supported Gendzwill's conclusions as to the shape and size of the mounds, but new evidence indicates that there may be significant undulations on their upper surface. All of the seismic sections examined have shown that the mounds are indeed relatively small, with tops ranging between 0.5 and 6 kilometres in diameter. In addition, the sections indicate that the mounds have steep slopes ranging up to 1:2. (Fig. 1).

There is a large amount of lateral and vertical variation in lithology and faunal content within the Upper Winnipegosis mounds. However, a lack of diagnostic fossils that could be used to establish time zones, together with the paucity of cored wells, makes it difficult to accurately define facies relationships. Streeton (1971) proposed an informal division of the lithofacies within the Upper Winnipegosis. A modified version of his classification is summarized below and outlined grapically in Figure 1.

LAMINATED MUDSTONE UNIT

This facies is a dense, fine grained, light to medium brown, extensively dolomitized carbonate mudstone. The unit usually contains vague, often wavy laminations caused by regularly spaced argillaceous-carbonaceous partings and stylolites. The known maximum thickness of this unit is 38 metres. It overlies the peloidal grainstone unit and can underlie the organic unit.

PELOIDAL GRAINSTONE UNIT

This unit is variable, ranging from well sorted peloidal grainstones to poorly sorted peloidal wackestones in which the peloids are supported by a matrix dolomite microspar and micrite. It has a maximum known thickness of 33.2 metres and is overlain either by the laminated mudstone unit or the fringing cap unit.

ORGANIC UNIT

This unit is very similar to the peloidal grainstone unit. It differs mainly in that it contains potentially 'frame-building' organisms such as stromatoporoids and corals, in addition to abundant peloids and oncolites. However, there is no evidence of *in situ* growth of these organisms. Abudant shell fragments are present.

FRINGING CAP UNIT

This unit is roughly equivalent to Wardlaw and Reinson's (1971) pisolite cap unit. It consists of oncoliths, peloids, extensively dolomitized intraclasts with concretionary coatings, and micritic matrix. It appears that the unit more commonly occupies a marginal position rather than being a cap covering the entire mounds as suggested by Wardlaw and Reinson (1971).

RATNER MEMBER

The Ratner Member is located between the Upper Winnipegosis mounds. It is underlain by the Lower Member and is overlain by the Whitkow Salt Member of the Prairie Evaporite. The Ratner is a finely laminated carbonate mudstone with abundant entErolithic anhydrite. It has a known maximum thickness of 16 metres. Wardlaw and Reinson (1971) recognized eight laterally persistent lithologic units which they labelled one to eight in ascending order.

WINNIPEGOSIS MOUNDS

In addition to showing the small aerial extent of the Upper Winnipegosis mounds, seismic surveys indicate that there is a relationship between subsidence in the overlying Prairie Evaporite and the occurrence of Upper Winnipegosis mounds. All of the seismic sections obatined in central Saskatchewan show a depression of the reflecting horizons over the Winnipegosis mounds as was first suggested by Gendzwill (1978) (Figure 2). The reflections from the top of the Prairie Evaporite show the most marked depression, while overlying reflections are less and less affected. The depression is not usually recognizable above the top of Devonian strata and never extends above the post-Palaeozoic unconformity. The depression is accompained by a measurable increase in the thickness of the units over the mounds. The repetition of these features on several seismic sections supports Gendzwill's (1978) suggestion that subsidence took place over the mounds during the Upper Devonian and Mississippian but ceased before the early Cretaceous. However, some mounds in southeastern Saskatchewan show no identifiable depression or thickening.

Several other features, including collapse structures, salt horses, and areas of water seepage and structural disturbance in potash mines also seem to be related to the mounds.

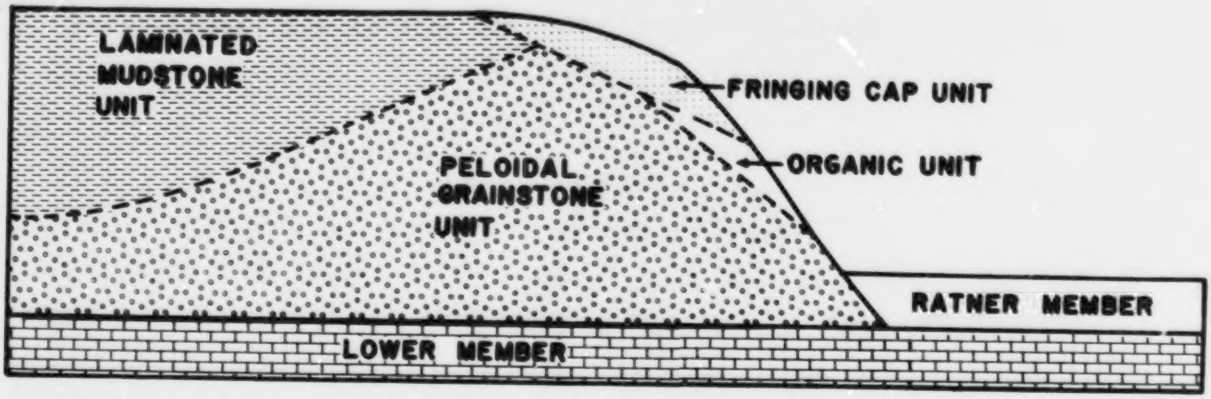

Fig. 1 - Subdivision of the Winnipegosis Formation in Saskatchewan. The distribution of lithofacies within the Upper Member is shown. See text for details.

Gendzwill (1978) suggested that the subsidence was due to limited dissolution of the base of the Prairie Evaporite over the mounds. Although this mechansim may have been involved, research in progress indicates that the diagenesis of the mounds may have been at least a factor in the subsidence. Petrologic investigation has revealed evidence of compaction, pressure solution and dolomitization, all of which would lead to a reduction in the volume of the mounds and hence subsidence over them. A detailed diagenetic sequence has not yet been established. The existence of some mounds with no associated depressions may help in unravelling the diagenetic sequence of those that have depressions.

The understanding of fluid migration, diagenetic processes and structures in the Winnipegosis will not only help explain the subsidence, but will assist in the recognition of potential reservoir rock within this formation.

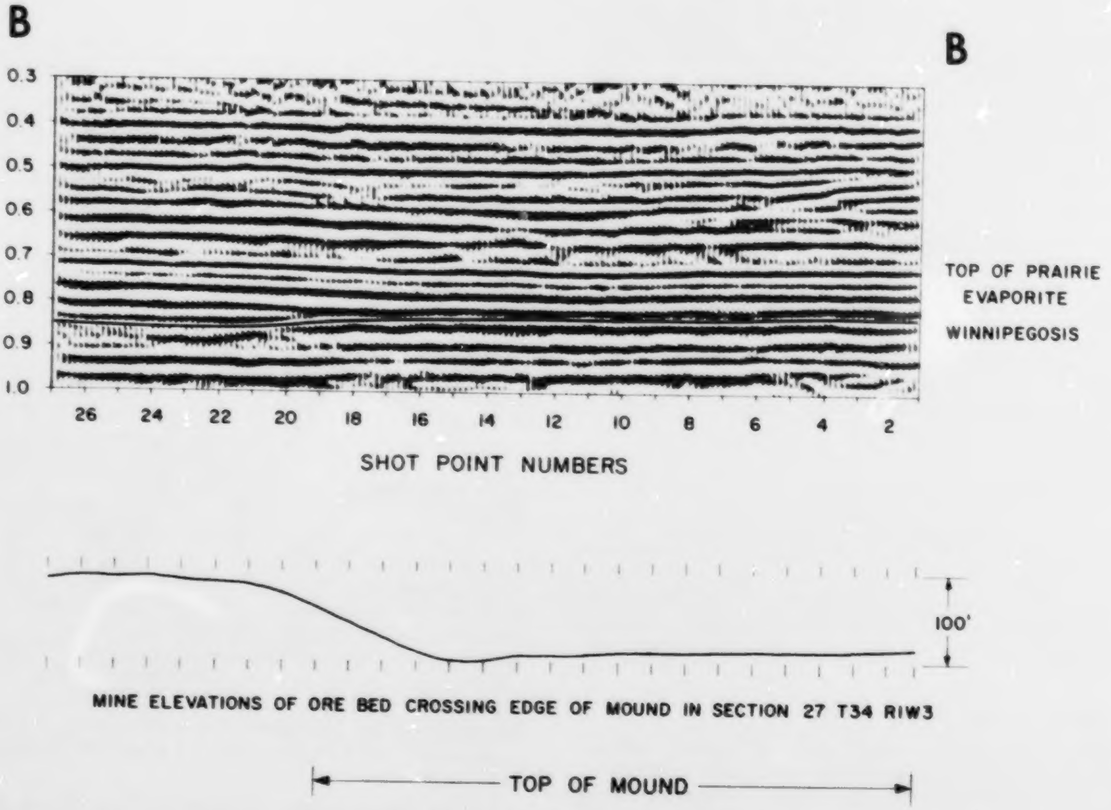

Fig. 2 - Seismic section showing Upper Winnipegosis Member mound and subsidence of overlying strata. Also shown is a mine-elevation profile taken along a line directly below the seismic profile, verifying subsidence shown by seismic data (from Gendzwill, 1978, Fig. 5).

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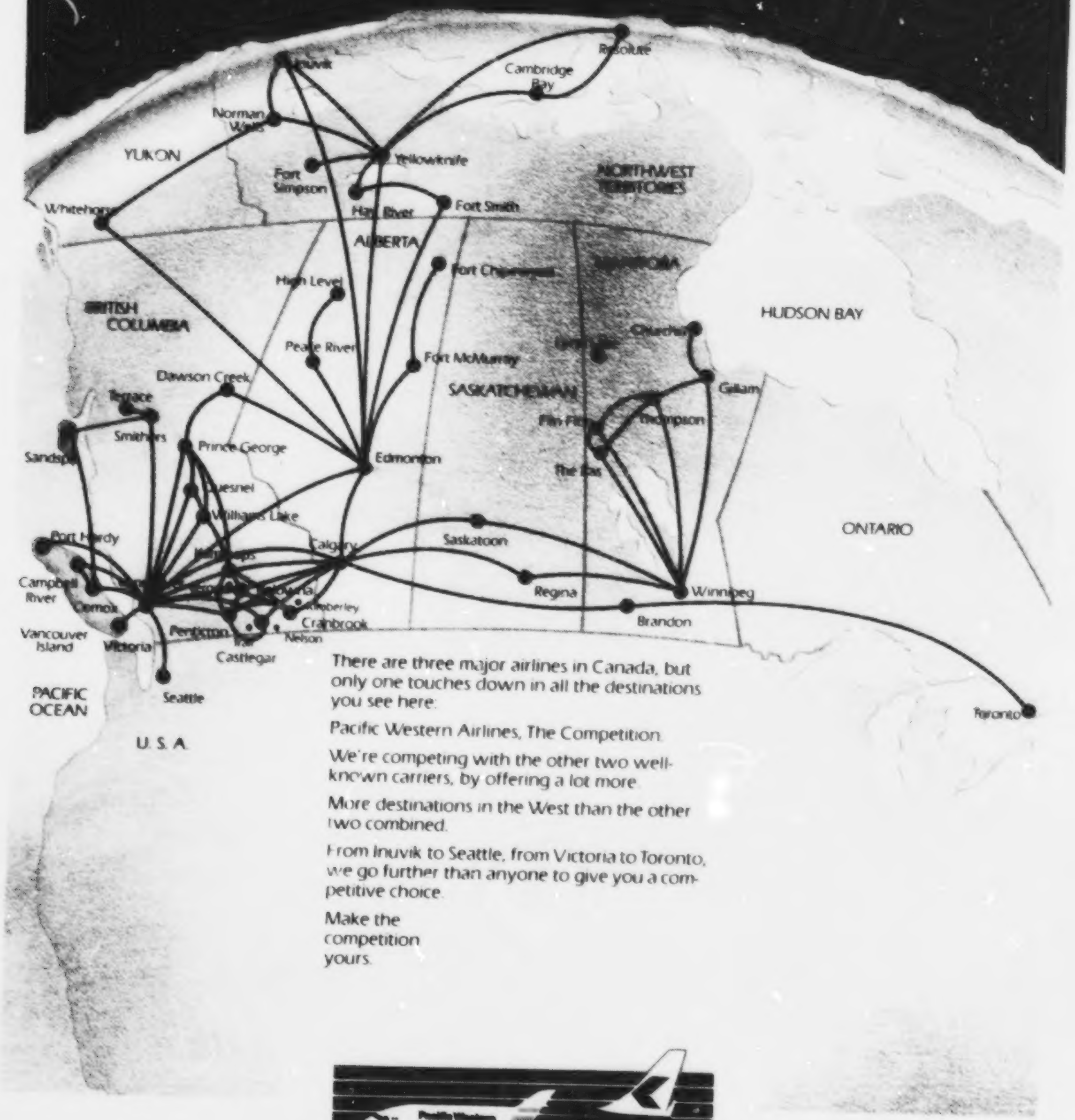
THE COMPETITION IS EVERYWHERE.


Inuvik
Resolute
Cambridge Bay
Norman Wells
YUKON
Yellowknife
Fort Simpson
NORTHWEST TERRITORIES
Whitehorse
Hay River
Fort Smith
ALBERTA
Fort Chipewyan
MANITOBA
High Level
BRITISH COLUMBIA
HUDSON BAY
Churchill
Peace River
Fort McMurray
Lynn Lake
Dawson Creek
SASKATCHEWAN
Gillam
Terrace
Flin Flon
Thompson
Smithers
Prince George
Sandspit
Edmonton
The Pas
Quesnel
Williams Lake
ONTARIO
Port Hardy
Kamloops
Calgary
Saskatoon
Campbell River
Comox
Kelowna
Regina
Winnipeg
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THE BAKKEN FORMATION IN THE WILLISTON BASIN OF WESTERN CANADA

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A suite of geological maps of the Bakken Formation (Upper Devonian-Lower Carboniferous) have been compiled in preparation for a study of its source rock potential. The maps display the extent, thickness and present structure of both the formation and its three members. Additional sheets indicating hydrocarbon shows and formation fluid characteristics are also available. A suite of illustrative cross-sections accompanies the maps.

The Bakken Formation is a thin unit exhibiting subdued changes in thickness, which generally conform to the regional structure of the basin. In the region of the Alberta-Saskatchewan border the combination of rapid thickness variations of the middle sandstone member and the pattern of pre-Cretaceous erosion produces a more complex geometry. Similar, but more local thickness variations of the middle sandstone member occur in the Rocanville-Virden area.

Local structural anomalies attributable to either salt solution collapse (Hummingbird, Saskatchewan) or meteorite impact (Hartney, Manitoba) are highlighted by the maps.

NATURE AND ORIGIN OF OOIDS AND PISOLITES OF THE MISSION CANYON FORMATION (MISSISSIPPIAN), WILLISTON BASIN, NORTH DAKOTA

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The ooids and pisolites in the Mission Canyon Formation (Mississippian) of North Dakota are dominated by a radially (normal) fibrous substructure. Scanning electron microscope and petrographic studies show a depositional origin for the radially fibrous substructure. Three types of ooids and pisolites with this substructure are common in the Mission Canyon: complete (unbroken), broken and recoated (1-4 stages), and composite (containing a complex nucleus). Depositional and diagenetic features associated with these ooids and pisolites are; (1) a range of fabrics from wackestone to grainstone; (2) fenestral, peloidal carbonates interbedded with and containig the ooids and pisolites; (3) cyanobacterial mats; (4) oncolites; (5) fibrous crusts; (6) restricted-marine organisms (ostracode and algae dominated); (7) desiccation cracks and tepee structures; (8) intraformational microerosional surfaces; (9) internal sediments; (10) fibrous and bladed isopachous cement.

The radially fibrous substructure of the ooids and pisolites point to formation in low energy environments. The associated depositional and diagenetic features indicate that a storm affected, tidal flat environment existed. Therefore, the ooids and pisolites probably formed in hypersaline pools on the tidal flats. Periodic storm surges agitated the pools and caused breakage of ooids and pisolites. Quiescent periods allowed renewed grain growth with the addition of radially fibrous coatings. Multi-staged growth textures show the periodic effects of storm surges until final deposition.

A facies mosaic was formed by several subenvironments (hypersaline pools, tepee structures, and cyanobacterial mats) on the tidal flat. Lateral migration of these subenvironments with burial produced the complex vertical succession of lithologies seen in core. This model differs from those of others who placed the ooids and pisolites, and associated lithologies, into parallel, linear, facies belts and called upon complex, transgressive-regressive, sea level changes to form the same lithologic successions.

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DEPOSITIONAL SETTING OF MISSISSIPPIAN STRATA IN SOUTHEASTERN SASKATCHEWAN: A CONCEPTUAL MODEL FOR HYDROCARBON ACCUMULATION

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Department of Geology
University of Regina
Regina, Saskatchewan, S4S 0A2

ABSTRACT

Mississippian rocks contain 75% or more of the proven oil reserves in the Williston Basin, much of which is concentrated in reservoirs that form arcuate trends along the northeast flank of the basin. These are subcrop trends, the traces of marker-defined units at the pre-Mesozoic unconformity.

The Mississippian was one of the few geologic periods when paleobathymetry of the Williston Basin area exerted an influence on the pattern of sediment distribution. Consequently, there are lateral facies changes from basin and basin slope deposits, through shallow water shelf carbonates to peritidal and continental sediments in several marker-defined units.

The basin and basin slope carbonates include sediments deposited under anaerobic conditions represented by faunally-deficient couplets of Kerogen-rich and Kerogen-poor lime mudstones, as well as dysaerobic deposits of horizontally and obliquely burrowed, poorly layered lime mudstones and skeletal wackestones. The shelf carbonates include: 1) outer shelf deposits represented by locally thick accumulations of crinoidal grainstones and packstone, as well as a zone of mixed fauna wackestones, wackepackstones and packstones; 2) shelf crestal deposits that include a range of coated grains concentrated in wackestones, wackepackstones, packstones and grainstones; and 3) inner shelf carbonates of burrowed, peloidal and skeletal lime mudstones and wackestones, as well as local accumulations of skeletal packstones and grainstones. Stromatolites, desiccation features, storm-layered sequences and displacive as well as layered anhydrites characterise the peritidal deposits. The entire succession represents a prograding, shallowing upward megasequence; within it there are both high and low energy shallowing upward repetitions, as well as brining upward cycles.

The subcropping reservoirs are associated with three types of traps: one, directly associated with the unconformity surface, is a diagenetic seal produced by pervasive anhydritization of the immediately subjacent carbonate rocks; the other two are due to lateral facies or textural changes within the carbonate succession. Other traps are structural; they represent regional tectonic uplift (Nesson and Cedar Creek Anticlines), local depositional draping or postulated astroblemes.

INTRODUCTION

Kent, (1984, in press, b) pointed out that the Mississippian was one of the few periods in the geological history of the Williston Basin when basin configuration exerted some influence on patterns of sediment distribution. In the deeper portions of the basin, the Mississippian can be described in vertical sequence as a mega-cycle beginning with shallow water sediments, (the Bakken Formation and the basal part of the Madison Group) passing upward into deeper water deposits (the lower Madison) and terminating in shallow water and continental rocks (the upper Madison and the Big Snowy Group). Near the margins of the basin, shallow water deposits make up the entire Mississippian section. Although Mississippian rocks are found only in the southern third of Saskatchewan, the sequence embraces both the mega-cycle of the basin centre and the shallow water deposits of the margins; the relationship between the basinal and marginal successions can be illustrated best through a depositional model.

GEOLOGICAL SETTING

The Madison Group, which constitutes the bulk of the Mississippian succession in southern Saskatchewan, attains a maximum thickness of 600 m in the extreme south-central portion of the province (Fig. 1). There is a marked attenuation of Madison thickness toward the zero edge, but only part of this can be attributed to depositional thinning, as the strata are truncated by at least two unconformities. One unconformity is related to a period of pre-Pennsylvanian erosion; the other represents a late Paleozoic to early Mesozoic erosional episode. The resulting hiatus appears to span approximately 150 million years. Progressively older strata have been truncated outward from the center of the basin. A distinctive topography that includes escarpments and cuestas, consequent and subsequent drainage systems and karst features has been imprinted on the eroded top of the Mississippian. This topography plays an important role in entrapment of hydrocarbons.

The Bakken and the basal part of the Madison can be considered to represent a transitional interval resulting from a change in structural configuration of the Williston Basin from Upper Devonian time to Mississippian time. At least on the northern flank of the basin, the basal part of the Madison is characterised by a widespread shallow, quiet water carbonate interval from about 1 to 50 m in thickness. Above the basal transitional interval, the Madison Group consists of several facies that appear to be progressively younger to the south and west (Fig. 2). In southeastern Saskatchewan and southwestern Manitoba, the facies boundaries are intersected by fairly thin marker beds composed of argillaceous or arenaceous terrigenous sediment in a carbonate matrix. Each of the markers has a characteristic geophysical well log signature, making them correlatable over southeastern Saskatchewan (Fig. 3). Because of their diachroniety with respect to facies boundaries and their thin, but areally extensive geometry the marker beds are considered to be synchronous. They are used to delineate seven stratigraphic units termed "Beds"; of these, only the youngest three (Midale, Ratcliffe and Poplar Beds; Table 1) can be recognized over a substantial area. The older units (Souris Valley, Tilston and Frobisher-Alida; Table 1) are confined to extreme southeastern Saskatchewan and southwestern Manitoba, in accordance with the distribution of the marker beds used to delineate them. The restricted extent of the older

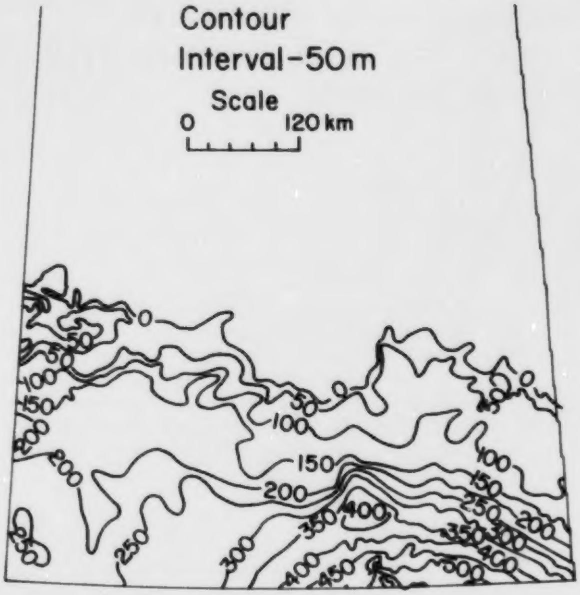

Contour
Interval-50 m
Scale
0
120 km
0
50
100
150
200
250
300
350
400
450
500

Fig. 1 - Isopach map of the Mississippian System in southern Saskatchewan.

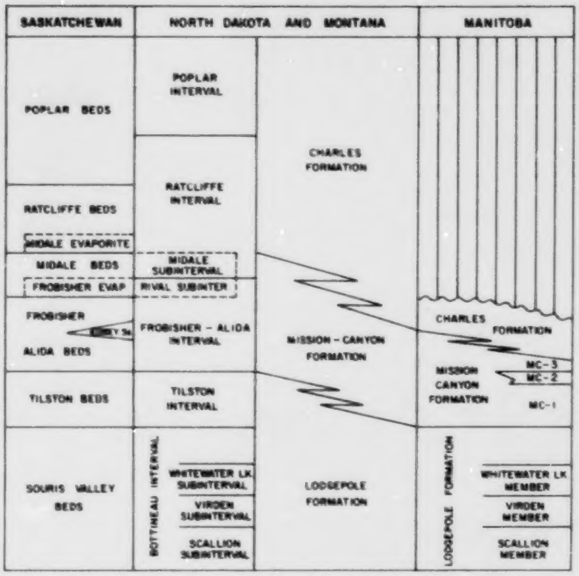

SASKATCHEWAN
NORTH DAKOTA AND MONTANA
MANITOBA
POPLAR BEDS
POPLAR INTERVAL
CHARLES FORMATION
RATCLIFFE BEDS
RATCLIFFE INTERVAL
MIDALE EVAPORITE
MIDALE BEDS
MIDALE SUBINTERVAL
FROBISHER EVAP
RIVAL SUBINTER
FROBISHER
KISBEY Ss
ALIDA BEDS
FROBISHER - ALIDA INTERVAL
MISSION - CANYON FORMATION
CHARLES FORMATION
MISSION CANYON FORMATION
MC-3
MC-2
MC-1
TILSTON BEDS
TILSTON INTERVAL
SOURIS VALLEY BEDS
BOTTINEAU INTERVAL
WHITEWATER LK SUBINTERVAL
VIRDEN SUBINTERVAL
SCALLION SUBINTERVAL
LODGEPOLE FORMATION
LODGEPOLE FORMATION
WHITEWATER LK MEMBER
VIRDEN MEMBER
SCALLION MEMBER

Table 1 - Stratigraphic correlation chart

marker beds may reflect a greater distance from the area in which they are preserved to a source of terrigenous sediments. In spite of the limited areal extent of some of the marker beds, many of the marker-defined units can be shown to contain two or three facies representing basinal, shallow shelf and peritidal conditions. An important adjunct to the development of the depositional model is the fairly well founded assumption that the pertitidal and shallow shelf rocks prograded basinward through much of Mississippian time (Fig. 2). Unfortunately, the prior existence of those facies in Early Mississippian (Kinderhookian) time is only sparsely documented from the rock record, since erosion at the pre-Mesozoic unconformity was sufficiently deep to remove most Late Kinderhookian strata. For the most part, the character of the Kinderhookian shallow shelf and peritidal sediments must be inferred from the Osagean rocks farther south and west. In the broadest sense, Mississippian strata above the transitional interval represent three major paleoenvironmental zones that form arcuate trends across southern Saskatchewan. Each zone may include several lithofacies that are distributed in a manner that indicate a specific relationship to the paleoshoreline. On the flanks of the basin the progradational relationship of facies may encompass both the Madison and Big Snowy Groups, since in southern Saskatchewan the basal strata of the Big Snowy

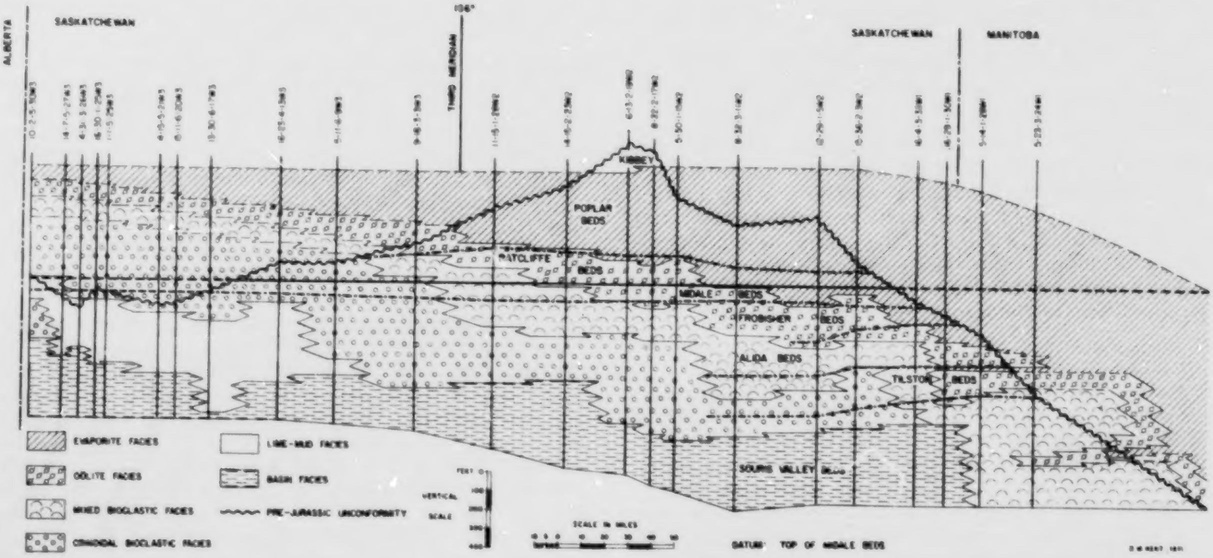

ALBERTA
SASKATCHEWAN
106°
THIRD MERIDIAN
SASKATCHEWAN
MANITOBA
KISBEY
POPLAR BEDS
RATCLIFFE BEDS
MIDALE BEDS
FROBISHER BEDS
ALIDA BEDS
TILSTON BEDS
SOURIS VALLEY BEDS
EVAPORITE FACIES
OOLITE FACIES
MIXED BIOCLASTIC FACIES
CRINOIDAL BIOCLASTIC FACIES
LIME-MUD FACIES
BASIN FACIES
PRE-JURASSIC UNCONFORMITY
FEET 0
100
200
300
400
VERTICAL SCALE
SCALE IN MILES
10 5 0 10 20 30 40 50
DATUM: TOP OF MIDALE BEDS

Fig. 2 - Schematic diagram showing the relationship of Mississippian magnafacies and marker-defined units in southern Saskatchewan (from Kent, 1974).

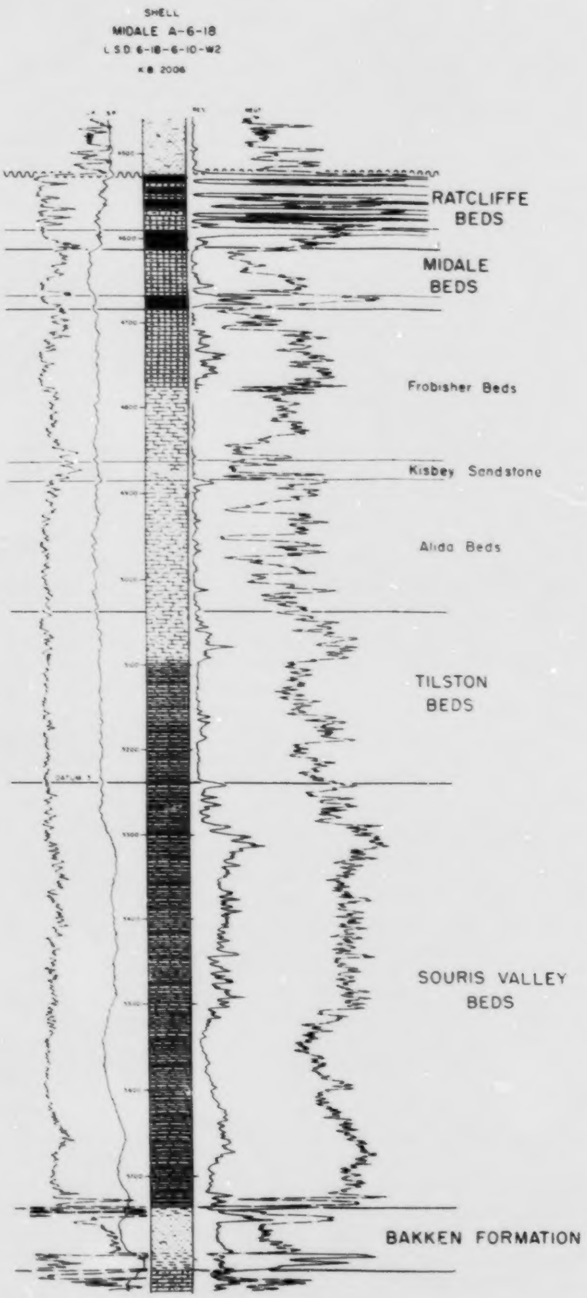


Fig. 3 - Geophysical well log illustrating log signatures of Mississippian marker-defined units in southeastern Saskatchewan (after Fuzesy, 1960).

Group are in gradational contact with the underlying Poplar Beds of the Madison Group.

In Saskatchewan, the Big Snowy Group is represented by the Kibbey Formation that is limited to a narrow region within a few kilometres of the International Boundary, in south-central Saskatchewan. Fuzesy (1960) described the Formation as red argillaceous sandstone, siltstone and claystone with interbedded limestones, dolomites and anhydrites. In some respects, the Kibbey is lithologically similar to overlying Mesozoic red beds of the Watrous Formation; it was most likely deposited under similar continental conditions (*cf.* Christopher, this volume). The remaining formations of the Big Snowy are preserved in Montana and North Dakota; they include lithologies that suggest variable depositional settings ranging from marine to non-marine. Thus the final phase of Mississippian sedimentation in the Williston Basin appears to have attained continental conditions.

THE DEPOSITIONAL MODEL

TRANSITIONAL BEDS

Bakken Formation

The Bakken Formation straddles the Devonian-Mississippian boundary and is subjacent to the carbonates of the Madison Group. The upper contact of the Bakken varies from conformable in the southeastern Saskatchewan to unconformable in the west where progressively older Bakken strata are overlain by basal Madison rocks. In extreme southwestern Saskatchewan, the Madison rests on the lowermost beds of the Bakken (Kent, 1974).

Where the total Bakken section is preserved, it includes upper and lower black to brownish-black, fissile to platy, kerogenous shale. The upper shale is fairly fossiliferous, containing conodonts, stunted chonetid brachiopods, spores and sporomorphs. In contrast, the lower shale contains mainly spores and sporomorphs.

The shales are separated by a coarser clastic interval. In the central portion of the basin this is predominantly a faintly laminated, rarely crossbedded, dolomitic siltstone or a very silty dolomite (Meissner, 1978). Farther north in southern Saskatchewan, the middle member is considerably more variable in lithologic character, with a basal, structureless, calcareous, silty sandstone overlain by an interval that is shaly in the southwest and sandy to the east (Christopher, 1961). The basal silty sandstone is undoubtedly marine, since it contains a brachiopod fauna. The overlying strata contain ooids in places; they become increasingly calcareous to the northwest, where a southeasterly trending elongate sedimentary body covering a couple of townships consists of quartzose oolitic limestone (Fig. 4). The sandstone in this upper interval is characterised by an abundance of sedimentary structures, including tabular crossbedding, ripples, scour marks and burrows. The shaly strata in the west interfinger with the sandstone and where this occurs pinstripe lamination and flaser bedding are present.

Transitional Carbonates (Basal Lodgepole)

These rocks at the base of the Madison Group in southern Saskatchewan are quite variable lithologically. On the Swift Current Platform, the basal Madison is composed of lime mudstone with scattered but diverse fossil remains. The fossils include crinoid ossicles, rare brachiopod shell fragments, ostracod valves, and fragments of fasiculate corals and fenestrate bryozoans. Glauconite, a common minor constitutent, occurs either as amorphous pellets seemingly unrelated to other rock constituents or as a replacement of skeletal remains. The transitional strata in the Platform area are colour-mottled, which appears to be due to patchy distribution of extremely fine pyrite. Some of the patches are suggestive of burrow traces. To the east and basinward the transitional beds

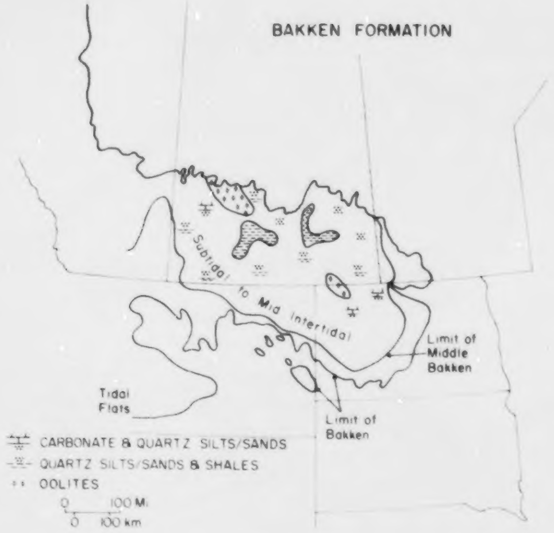


Fig. 4 - Simplified facies map of the middle sandstone member of the Bakken Formation (from Kent, 1984).

become increasingly more argillaceous. In southwestern Manitoba and eastern North Dakota they form part of the Routledge and Carrington Shales (Bjorlie and Anderson, 1978). In central Montana the transitional beds acted as a platform for growth of Waulsortian type bioherms (Smith, 1972, 1982) and Bjorlie and Anderson suspect that similar mounds may exist at the same stratigraphic level in eastern North Dakota.

Depositional History

The black shales of the Bakken could easily be interpreted as deep basin deposits, but the medial sand and silt interval appears to represent deposition in a shallow water environment. Considerable fluctuation in sea level would be required to sandwich a shallow water deposit between two deeper water intervals. It is more likely that the shales were formed on a broad platform over which wave intensity was dampened because of the shallow water depth; fine clastic sediments would have been virtually undisturbed and any organic material deposited with the mud would not have been winnowed.

The transitional beds of the Swift Current Platform area are thought to have been laid down below fair weather wave base; they may have been part of the initial basin slope deposits. The more shaly beds are probably basinal deposits.

MADISON GROUP

The sequence above the transitional interval can be divided stratigraphically and areally into deposits laid down in various water depths and under different chemical conditions. Water chemistry is significant particularly in terms of dissolved oxygen, which appears to have influenced sediment types and indigenous fauna and flora. Early Mississippian sediments appear to have been deposited on a ramp-like topography with sufficient variations in dissolved oxygen and water depth to create recognizable basin, slope, and shelf settings on the ramp surface (Fig. 5). The basinal deposits were laid down under anaerobic conditions, those of the lower slope in dysaerobic waters and an aerobic environment prevailed in the upper slope and shelf setting. In later Mississippian time the basin was less restricted and the slope was much more gentle because of basin infill; the waters were somewhat better oxygenated, leading to dysaerobic and aerobic conditions within the basin and on the slope (Fig. 6). Because of the change in water chemistry, the distinction between basinal and inner shelf sediments is difficult.

The anaerobic deposits consist of alternating dark and lighter coloured, finely laminated, bituminous, lime mudstone; the colour variation reflects the concentration of bituminous material, (Figs. 7-1 and 7-3). In central Montana outcrops, these rocks are dark gray to black and thinly bedded with very thin partings of platy calcareous shale. The main sedimentary structures are small scour channels, planar crossbedding, and truncated laminae. *Zoophycus* is a common trace fossil. Elsewhere in the same part of Montana the layering of the basinal rocks is interrupted by masses of carbonate as much as 300 m across at the base and up to 60 m thick. They have been identified as Waulsortian-type mounds (Cotter, 1965; Smith, 1972, 1982). The mounds are dominated by lime mudstones and skeletal wackestones. Despite their massive appearance in outcrop, close examination shows evidence of growth accretion of alternating layers of lime mudstone and crinoidal wackestones or wackepackstones. In addition to abundant crinoids, other common organisms include: brachiopods, ostracodes, bryozoans, cephalopods, trilobites, echinoids, foraminifera and tabulate corals. Submarine cementation of large portions of the mounds was effected by precipitation of radiaxial fibrous calcium carbonate cement on all free internal surfaces. In places this cementation appears similar to stromatactis. The mounds are draped into a cyclic sequence of thinly bedded skeletal wackestones capped by crinoidal and oolitic grainstones. The laminated and thinly bedded strata probably represent deposition in a basinal environment. The mounds apparently developed in that environment as well, since they are immediately underlain by typical transitional beds. In the subsurface, Bjorlie and Anderson (1978) speculated that Waulsortian type mounds are present in east-central North Dakota and western Manitoba, although this has not been clearly sustantiated. In addition, Smith (1982) reported a possible mound on the Cedar Creek Anticline.

The dysaerobic zone may be similar in part to the tidal shelf described by Wilson (1970). The rocks proximal to the basinal deposits are dark gray, burrowed, pyritiferous, argillaceous lime mudstones (Fig. 7-2), suggesting an environment that was poorly oxygenated but not completely hostile to benthic organisms, as indicated by the presence of burrows. Higher up the slope in the dysaeorbic zone the deposits are non-argillaceous lime mudstones that in many cores are essentially devoid of macrofossil remains with the exception of intervals rich in aggregations of spicules or spines, most of which are silicified. However, in the outcrops of central Montana and in at least one core in southern Saskatchewan deposits representing the lower slope dysaerobic zone contain brachiopod, crinoid and bryozoan remains. The two basic lithologies of the dysaerobic zone are in gradational contact and interdigitate; where they are intermixed there is evidence of slumping. Therefore, these sediments may be interpreted to represent deposition on a low gradient slope under dysaerobic conditions.

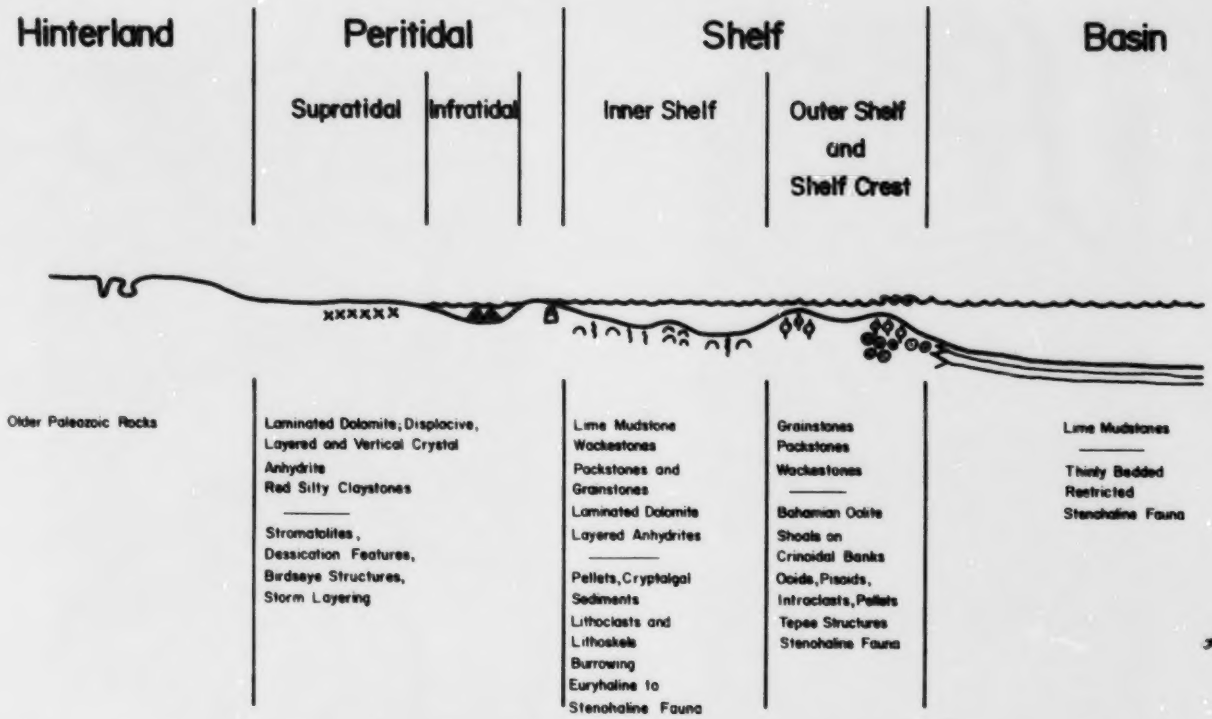

Hinterland
Peritidal
Supratidal
Infratidal
Shelf
Inner Shelf
Outer Shelf and Shelf Crest
Basin
Older Paleozoic Rocks
Laminated Dolomite; Displacive, Layered and Vertical Crystal Anhydrite
Red Silty Claystones
Stromatolites, Dessication Features, Birdseye Structures, Storm Layering
Lime Mudstone
Wackestones
Packstones and Grainstones
Laminated Dolomite
Layered Anhydrites
Pellets, Cryptalgal Sediments
Lithoclasts and Lithoskels
Burrowing
Euryhaline to Stenohaline Fauna
Grainstones
Packstones
Wackestones
Bahamian Oolite Shoals on Crinoidal Banks
Ooids, Pisoids, Intraclasts, Pellets
Tepee Structures
Stenohaline Fauna
Lime Mudstones
Thinly Bedded
Restricted
Stenohaline Fauna

Fig. 5 - Sketch cross section illustrating proposed facies relationships in the Early Mississippian of southern Saskatchewan.

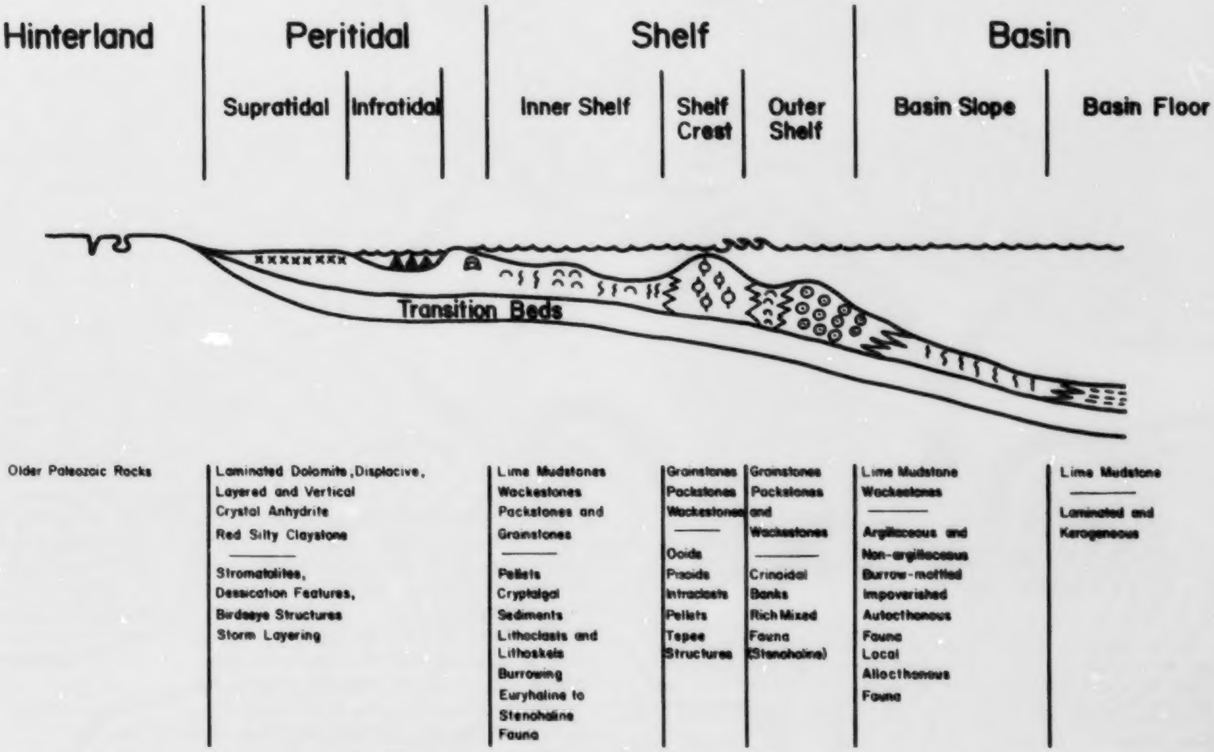
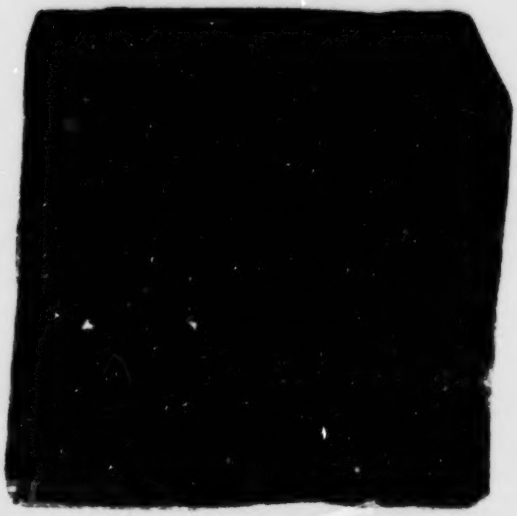

Hinterland
Peritidal
Supratidal
Infratidal
Shelf
Inner Shelf
Shelf Crest
Outer Shelf
Basin
Basin Slope
Basin Floor
Transition Beds
Older Paleozoic Rocks
Laminated Dolomite, Displacive, Layered and Vertical Crystal Anhydrite
Red Silty Claystone
Stromatolites, Dessication Features, Birdseye Structures
Storm Layering
Lime Mudstones
Wackestones
Packstones and Grainstones
Pellets
Cryptalgal Sediments
Lithoclasts and Lithoskels
Burrowing
Euryhaline to Stenohaline Fauna
Grainstones
Packstones
Wackestones
Ooids
Pisoids
Intraclasts
Pellets
Tepee Structures
Grainstones
Packstones and Wackestones
Crinoidal Banks
Rich Mixed Fauna (Stenohaline)
Lime Mudstone
Wackestones
Argillaceous and Non-argillaceous
Burrow-mottled
Impoverished Autocthonous Fauna
Local Allocthonous Fauna
Lime Mudstone
Laminated and Kerogeneous

Fig. 6 - Sketch cross section illustrating proposed facies relationships in younger Mississippian (Midale and Ratcliffe Beds) strata of southern Saskatchewan.

1

2



3

Fig. 7 - 1) Upper Madison laminated, bituminous, improverished, lime mudstone. Note the truncation surface (arrow). Christie Quintana Melaval No. 1 2-14-8-4W3, 1568.6 - 1568.7 m (from Kent, 1974). 2) Upper Madison mottled, argillaceous, improverished, lime mudstone. Mottling is probably related to intense burrowing and sediment churning. Note the large pyrite crystal to the right of centre. Sohio Standard Wood Mountain No. 1 16-10-4-4W3, 1951.6 m (from Kent, 1974). 3) Upper Madison laminated, bituminous, improverished, lime mudstone. Christie Quintana Melaval No. 1 2-14-8-4W3, 1568.7 m (from Kent, 1974).

The aerobic zone is represented by a variety of shallow water sediment types, beginning with those interpreted as representing outer shelf and shelf crestal deposits, passing through a variety of inner shelf sediments and ending in peritidal deposits. The outer shelf rocks include crinoidal bank and bank foreslope deposits; the former are made up of several decametres of crinoidal grainstones, ranging from arenite to rudite size (Fig. 8). The foreslope deposits are interbedded calciruditic and calcarenitic grainstones and skeletal wackestones. Load and slump structures are particularly common at grainstone/wackestone interfaces. Immediately landward from the outer shelf crinoidal deposits, the rocks consist of grainstones, packstones and wackestones containing a variety of skeletal remains (Fig. 5). These apparently represent a somewhat less agitated region than that of the crinoidal banks, possibly protected by them. These sediments pass laterally into shelf crestal rocks that are composed of a variety of coated and non-coated grains including pisoids, ooids, coated intraclasts, intraclasts and peloids (Akhurst, 1984; Fig. 9). Texturally, these rocks are composed of grainstones, packstones and wackestones with well-developed fenestral porosity. In places the allochem sequence is interrupted by laminated crusts (Fig. 9). Crabtree (1982) has shown that these shelf crestal deposits are dissected by narrow linear features that contain argillaceous lime mudstones as well as bidirectional crossbedded, pelleted grainstones and rounded intraclasts. He interprets these deposits as tidal channel-fill sediments. Because of their similarity to the Yates Formation of the Permian Reef Complex in west Texas and New Mexico, Gerhard *et al.* (1978) interpreted a vadose origin for the shelf

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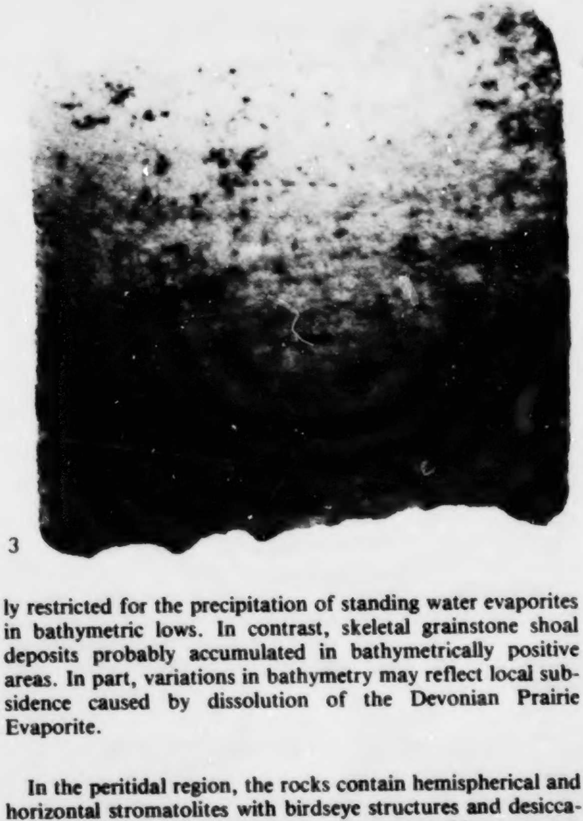

3

Fig. 8 - 1) Upper Madison poorly sorted calcite-cemented crinoidal grainstones, with large portions of pebble size skeletal particles are typical of high energy zone of crinoidal banks. S. P. C. Hatton 10-21-14-28W3, 1046.9 - 1047.0 m (from Kent, 1974). 2) Upper Madison crinoidal grainstone, poorly sorted with granule and pebble size skeletal particles. Amurex, *et al.* Kieville 4-27-15-25W3, 1073.2 m (from Kent, 1974). 3) Upper Madison compacted crinoidal grainstone, displaying medium to fine sand size, relatively close packing of skeletal particles and scattered patches of micrite. Amurex Albercan McCloud 15-12-10-27W3, 1234.4 m (from Kent, 1974).

crestal deposits, but Akhurst (1984) considers the same deposits to represent a more complex history that includes periods of high energy, times of quiescence and intervals of exposure involving vadose diagenesis. The shelf crestal rocks and outer shelf crinoidal banks are locally juxtaposed, and in fact, oolites may cap the crinoidal banks (Smith, 1972).

The inner shelf environment is dominated by pelleted and burrowed lime mudstones and wackestones. However, a variety of other sediments have been recognized including skeletal packstones and wackestones, cryptalgal lime mudstones as well as lithoclastic and lithoskeletal wackestones and lime mudstones. There must have been sufficient change in the bathymetry of the sublittoral environment to cause some distinct differences in biota, for the skeletal remains are typically euryhaline in places, but stenohaline elsewhere. At times, parts of the inner shelf region must have been sufficiently restricted for the precipitation of standing water evaporites in bathymetric lows. In contrast, skeletal grainstone shoal deposits probably accumulated in bathymetrically positive areas. In part, variations in bathymetry may reflect local subsidence caused by dissolution of the Devonian Prairie Evaporite.

In the peritidal region, the rocks contain hemispherical and horizontal stromatolites with birdseye structures and desiccation features. The deposits are also characterised by an assortment of anhydrite types ranging from nodular and mosaic to layered and vertical crystal growth forms, representing both displacive (Fig. 10) and standing water origins. Shallowing upward evaporite cycles are common in these deposits, indicating changes from a salina or restricted "maritime-lake" depositional setting to a supratidal flat. In places the displacive

Fig. 9 - Ratcliffe Beds shelf crestal grainstone composed of a variety of coated grains. Laminated crusts may represent calcrete horizons. Dipping strata at the top of the specimen may represent the flank of a tepee structure. Hudson Bay Miami Hummingbird 11-26-2-19W2, 1888.5 m.

anhydrites have formed in reddish, finely crystalline dolomites suggesting proximity to a continental environment.

In vertical succession, the aerobic zone lithologies constitute several shallowing upward cycles; each cycle records progradation of supralittoral sediments progressively farther into the basin. Although some of the older shallowing upward cycles have been truncated by the pre-Mesozoic erosion surface, there is sufficient continuity of lithologies to indicate that the dysaerobic and aerobic sediment zones trace roughly arcuate patterns around the basin. In Saskatchewan, the distribution of lithofacies follows the present erosional limit of the Mississippian (Fig. 11). There is sufficient evidence in the preserved strata to indicate that the early Mississippian paleoshoreline was no more than 150 km beyond the present erosional limit.

ECONOMIC CONSIDERATIONS

In the Williston Basin area, the Bakken is unique in that it has both potential reservoir and source rocks. Williams (1974) found that hydrocarbons from Devonian and Mississippian reservoirs contain organic geochemical components similar to the hydrocarbons from the Bakken shale source rocks. Dow (1974) used a series of maps of the Bakken and related oil types to speculate on migration paths. He suggested that the oil was generated in the central portion of the Basin, in the vicinity of the Nesson Anticline. The oil presumably migrated upward

Fig. 10 - Frobisher Evaporite, typical peritidal lithologies, including displacive anhydrite in stromatolitic layers. Note the hemispherical stromatolites. Shell Benson Unit 7-30-6-8W2. 1348.4 m (from Kendall, 1978).

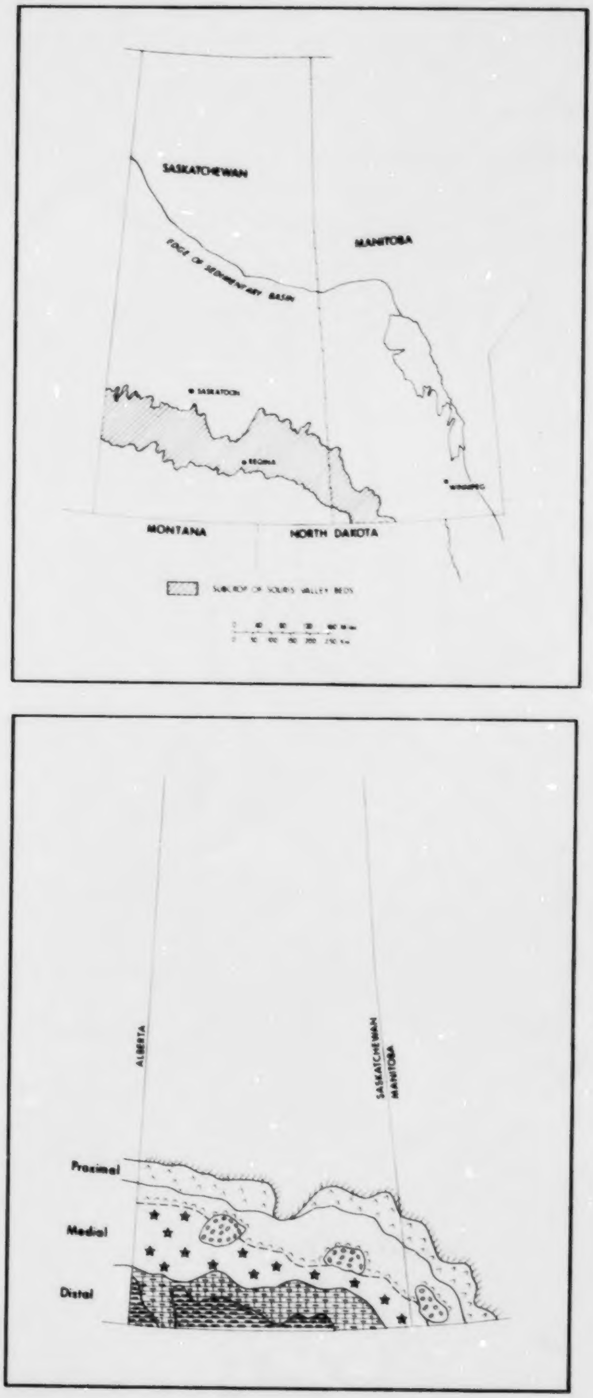

Fig. 11 - Souris Valley subcrop and Lower Madison facies in southern Saskatchewan.

along fractures to the crest of the anticline and spread out from there, filling traps on the anticline and eventually moving out to the margins of the Basin. Dow suggested that peak generaton occurred in the Cretaceous and that a sufficient volume of source rock is present in that part of the basin to produce abut 1.6 billion m³ of oil, about 93% of the presently discovered oil in place.

Oil shows are common in the middle Bakken (Christopher, 1961; Meissner, 1978), but to date there are only a few fields in the Basin in which oil is produced from that interval. There are about six areas in the U.S. portion of the Basin in which the Bakken is productive, but only the Antelope Field contains large reserves. In the Saskatchewan portion of the Basin, there are two Bakken fields, Roncott and Rocanville, as well as several one or two well producing areas. Meissner (1978) suggested that in the U.S. fields, oil storage volume was established in the relatively low porosity strata of the middle Bakken and permeability was enhanced by fracturing, probably due to flexure of reservoirs over basement block faults. Both Roncott and Rocanville are also located on structural highs, but fracturing does not appear to be a significant feature of the reservoirs (Christopher, 1961; von Osinski 1970). The reservoirs are friable, silty sandstone and it appears that, at least at Roncott, porosity and permeability have been enhanced by dolomitization of the original calcium carbonate cement.

All of the hydrocarbon accumulations in the Bakken of the Williston Basin area are medium to light oil. However, in west central Saskatchewan, substantial heavy oil reserves occur in the middle sandstone member in eight fields, including three recent discoveries (the Cactus Lake, Plover Lake and Luseland Fields). In 1958, Reasoner and Hunt showed that most of the heavy oil occurrences then known were located on positive structural elements that they considered to be associated with dissolution of evaporites in the Torquay Formation of the Three Forks Group; Kents (1959) concurred with these conclusions. More recently, the Cactus Lake, Coleville and Buffalo Coulee Pools have been interpreted to represent traps associated with the erosionally dissected pre-Mesozoic unconformity surface (Ducharme and Murray, 1980). Where Lower Cretaceous shales of the Mannville group overlie the unconformity, oil is trapped only in the Bakken; where basal Mannville sands directly overlie the middle Bakken, Mississippian and Cretaceous sands form a single, contiguous reservoir.

The source of the heavy oil in the Bakken is not clear. It may have been the Bakken shales as suggested for the Williston Basin area, but local generation of oil is unlikely, inasmuch as it is doubtful that the shales have been buried to sufficient depth for thermal maturation. Ducharme and Murray, (1980) reported an analysis from the Cactus Lake Pool that suggests a Bakken source; this inference is somewhat doubtful, insofar as the Cactus Lake crude is highly altered. Another possible source is downdip leakage from the Cretaceous sands superjacent to the Bakken subcrop; this could be expected if formation pressure is lower in the Bakken than in the overlying strata. A conclusive interpretation of the origin of Bakken heavy oil awaits future investigations. Comparative studies of oil composition and alteration are required. Reflectance studies of the Bakken shales throughout western Saskatchewan would yield some indication of the degree of thermal maturation of organic matter, and hydrodynamic studies of the Bakken and overlying Cretaceous sands might determine whether or not a cross-formational downdip hydrodynamic gradient does, indeed, exist.

Future discoveries in the Bakken of the Williston Basin area probably will be made on basement block fault structures or multistage salt solution features. Heavy oil accumulations in west central Saskatchewan are likely to be found near the subcrop of the middle Bakken, particularly associated with positive structural elements.

Oil traps in Mississippian carbonate strata comprise four fairly distinct categories. However, subtle variations add some variety to the main types. The categories include: Type 1 traps subjacent to the sub-Mesozoic unconformity; Type 2 traps on regional structural features; Type 3 traps associated with local drape structures; and Type 4 traps created by astroblemes.

Type 1 traps are the most common. Figure 12 shows that Mississippian oilfields on the northeast flank of the Williston Basin mimic the trend of subcrops of the marker-defined units below the pre-Mesozoic unconformity. Fields lying along the subcrop trend of a particular marker-defined unit invariably produce oil form that interval (Figs. 10, 11). Because the unconformity truncates various marker-defined units, diverse subcropping lithologies represent several different facies (Fig. 13). Shelf marginal deposits form the subcrop of the Souris Valley Beds (upper part), the Tilston Beds, and the Frobisher-Alida Beds (lower part). In contrast, sublittoral rocks interdigitating with littoral and supralittoral rocks constitute the subcropping facies for the upper part of the Frobisher-Alida and the Midale Beds (Fig. 13).

The variations in lithologies immediately beneath the unconformity account for three subtypes of unconformity traps. They are: a) porosity-permeability decrease in the updip direction; b) porosity-permeability sealant immediately subjacent to the unconformity surface; c) facies change beneath the unconformity. Type 1a is caused by textural variations (grainstone or packstone passing into micritic rock) or

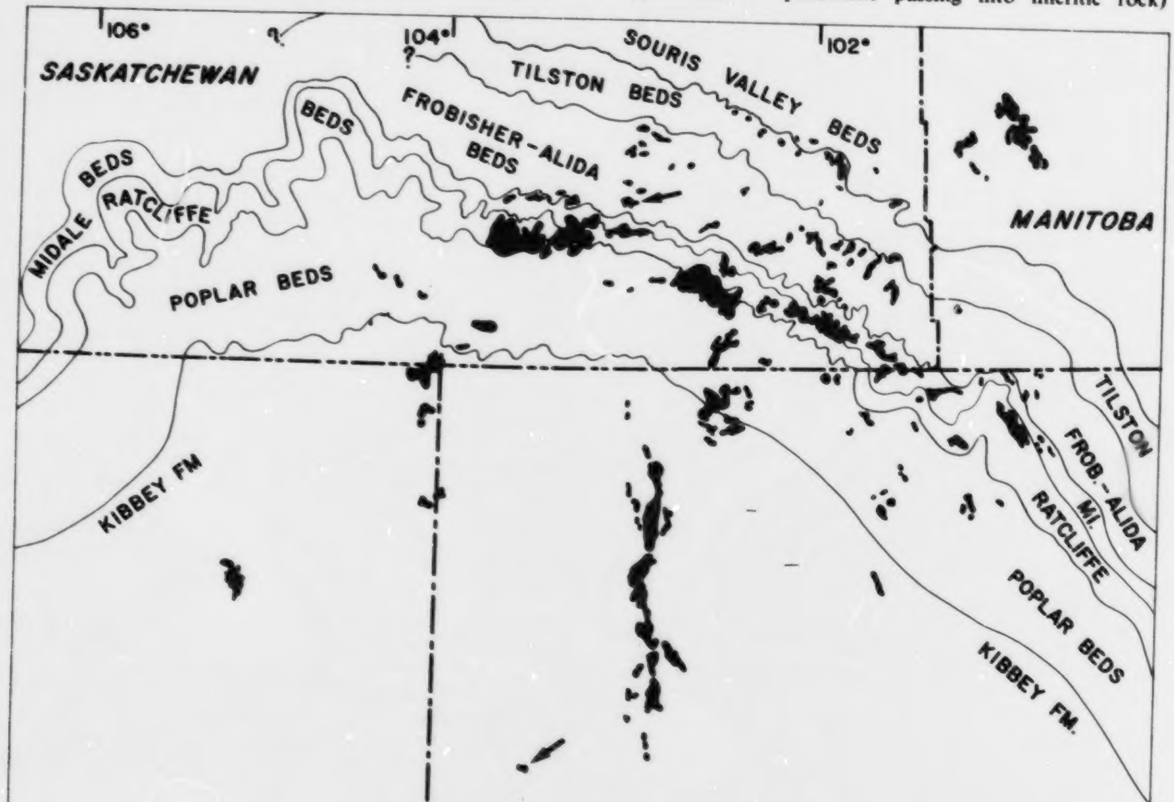
106°
?
104°
?
102°
SASKATCHEWAN
SOURIS VALLEY BEDS
TILSTON BEDS
FROBISHER-ALIDA BEDS
BEDS
BEDS
RATCLIFFE
MIDALE
POPLAR BEDS
MANITOBA
TILSTON
FROB.-ALIDA
MI.
RATCLIFFE
POPLAR BEDS
KIBBEY FM.
KIBBEY FM
MONTANA
NORTH DAKOTA
0 15 30 Mi
0 25 50 km
106°
104°
102°

Fig. 12 - Mississippian subcrop trends and related oilfields in the Williston Basin (from Kent, in press, a).

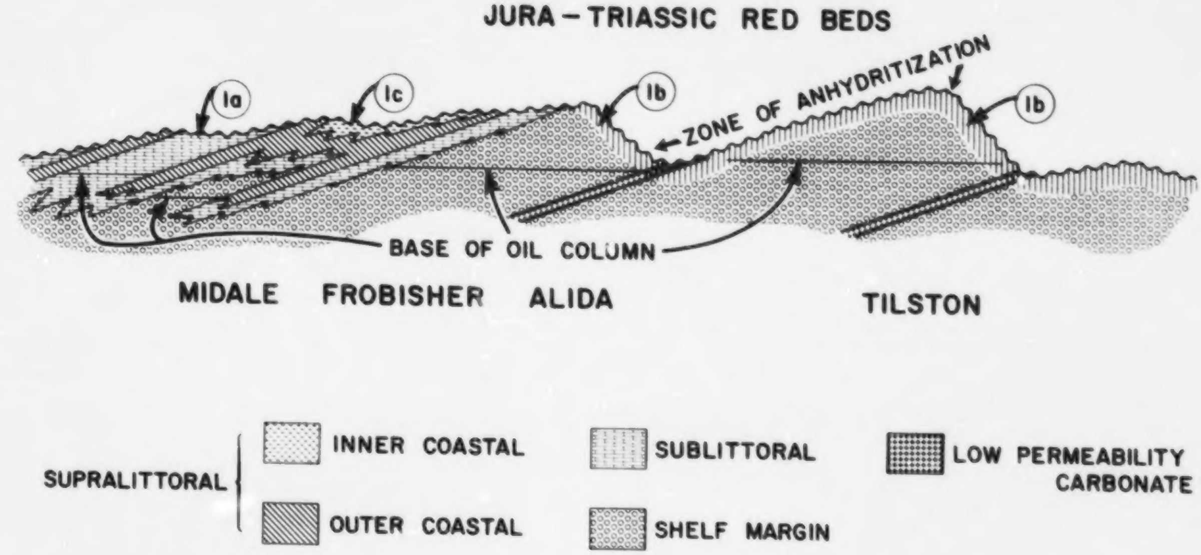

Fig. 13 - Schematic cross-section of Type 1 oil occurrences in the Williston Basin (from Kent, in press, a).

diagenetic differences (dolomite passing into limestone or uncemented strata passing into cemented rocks). Type 1b is due to anhydritic seals and 1c is illustrated by Figure 13.

Type 2 traps are the next most abundant; they are represented by oil accumulations at several localities along a linear structural feature, such as the Nesson or Cedar Creek Anticlines. Combinations of porosity-permeability pinchouts and fracturing create reservoirs on these structures.

Type 3 traps are local features seldom exceeding 10 km in length and 6 km in width. They appear as southeast trending nose-like anomalies on structure contour and seismic maps. They are most common in northeast Montana, extreme northwest North Dakota and southcentral Saskatchewan. The structures may be single or multi-zone producers with production from strata ranging in age from Ordovician to Mississippian. The structures may originate by basement block faulting or multi-stage salt solution. Reservoirs are commonly porosity-permeability pinchouts enhanced by fracturing.

Type 4 traps are a special type that have been identified at two localities, Viewfield in Saskatchewan and Red Wing Creek in North Dakota. Considerable controversy has accompanied their interpretation as astrobleme structures; a discussion of the validity of such interpretations is beyond the scope of this paper.

Future exploration in Madison strata probably will continue to be concentrated in the vicinity of the known oil discoveries. However, the Tatagwa area of Saskatchewan indicates that shelf marginal grainstone deposits somewhat removed from the subcrop may be potential exploration targets.

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A LITTLE KNOWN CARBONATE RESERVOIR WITHIN THE LOWER LODGEPOLE FORMATION, NORTHWESTERN NORTH DAKOTA

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ABSTRACT

The Lodgepole Formation in northwestern North Dakota has been divided into three subintervals — the lower and upper Lodgepole and a middle carbonate unit. A potential petroleum reservoir exists in the carbonate unit. Described as a silty limestone to an argillaceous limestone, this subinterval has a maximum thickness of 39 metres (128 ft) with a potential pay zone of approximately 9 metres (30 ft). The types of porosity indicated from log characteristics are matrix and fracture porosity. Four wells have produced from this subinterval.

Lodgepole time was a period of inactivity along the Nesson and Antelope anticlines. Isopach maps suggest a major western structure was prominent during the deposition of the carbonate unit. This structure may be related to the Central Plains Conductivity Anomaly or to the Fromberg-Colorada-Wyoming shear zone. However, no indications of it are apparent on structure maps. Later movement of the Nesson and Antelope anticlines and the western structure have resulted in the fracturing of the carbonate unit.

Sedimentation patterns suggest that the sediment source was the Elk Point basin. This places the reorientation of seaways from the Elk Point basin to the Central Montana trough at least as late as middle Lodgepole (Early Mississippian) time.

INTRODUCTION

The Lower Mississippian Lodgepole Formation is present in the subsurface over approximately two-thirds of the state of North Dakota and represents the maximum transgression of the Mississippian seas. In the central portion of the Williston Basin, it conformably overlies the Bakken Formation and it unconformably overlies older formations along the basin margin. The Lodgepole Formation is overlain conformably by the Mission Canyon Formation, except along the basin margin where it is unconformably overlain by Mesozoic strata.

A carbonate unit which was originally described by Carlson and Anderson (1966) is present in the lower Lodgepole Formation in the northwestern portion of the state of North Dakota. The purpose of this paper is to describe the distribution and lithology of this unit and discuss its potential as a possible petroleum reservoir.

REGIONAL CORRECLATION AND NOMENCLATURE

Peale (1893) first applied the term "Madison" to the Lower Mississippian rocks in Montana and Wyoming where he recognized three distinctive limestone lithologies. Weed (1899) applied the term Madison group to these rocks and referred to them as the Paine Shale, Woodhurst Limestone, and Castle Limestone, in ascending order. Collier and Cathcart (1922) formally raised the Madison to group status and included two formations, the lower, Lodgepole Limestone and, the upper, Mission Canyon Limestone (Fig. 1). Discarding the name Castle Limestone, Sloss and Hamblin (1942) reduced the Paine Shale and Woodhurst Limestone to members within the Lodgepole Formation.

In 1956, the Mississippian Names and Correlation Committee of the Saskatchewan Geological Society re-evaluated the nomenclature of Saskatchewan, Manitoba, North Dakota, and Montana (Fig. 1). To avoid problems encountered with the facies changes of the Lodgepole, Mission Canyon, and Charles Formations, the Society applied the term "beds" to the units. The subdivisions are based on characteristic markers on gamma ray and electric logs and on a regional scale, may display both lateral and vertical facies changes. The subdivision equivalent to the Lodgepole was referred to as the Souris Valley Beds.

McCabe (1959), recognizing the time-transgressive nature of the Madison Group, re-evaluated the concept of formation with respect to the Lodgepole, Mission Canyon, and Charles, and considered them to be valid formations (Fig. 1). He also subdivided the Lodgepole Formation into marker-defined units based on gamma ray and electric log responses for regional stratigraphic studies.

In 1960, Smith presented a revised version of nomenclature for the Williston Basin (Fig. 1). He reduced the Madison Group to formational status and reduced the Lodgepole, Mission Canyon, and Charles Formations to facies of the Madison Formation. Five marker-defined intervals were recognized — the lowest, the Bottineau Interval, is considered to be equivalent to the Lodgepole.

The Madison Formation was again raised to group status and its facies raised to formations by Bluemle, Anderson, and Carlson, (1980) (Fig. 1). The marker-defined intervals defined by Smith (1960) were retained. This nomenclautre is currently being used by the North Dakota Geological Survey and is used in this paper.

DESCRIPTIVE STRATIGRAPHY

REGIONAL STRATIGRAPHY

Two main facies of the Lodgepole Formation are known to exist: a central basin facies and a shelf facies. The central basin facies is a dark grey to black, interfingering sequence of argillaceous limestone, calcareous shale, and clean, fragmental to finely crystalline limestone (McCabe, 1959). It conformably ovelies the black shales of the Bakken Formation and is conformably overlain by the carbonates of the Mission Canyon Formation. In the central portion of the basin similarities in log characteristics make the Lodgepole-Mission Canyon cantact almost impossible to identify.

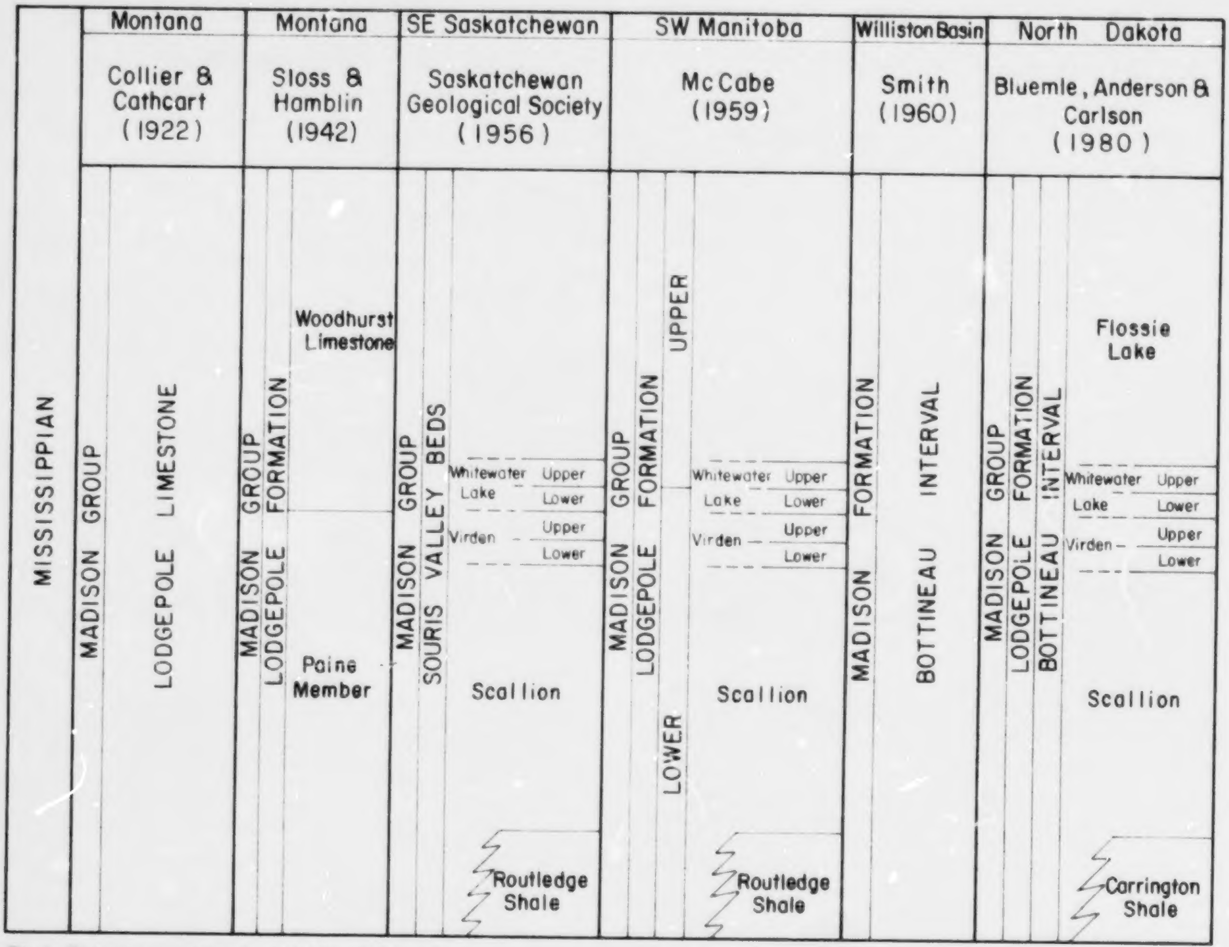

Montana
Collier & Cathcart (1922)
Montana
Sloss & Hamblin (1942)
SE Saskatchewan
Saskatchewan Geological Society (1956)
SW Manitoba
McCabe (1959)
Williston Basin
Smith (1960)
North Dakota
Bluemle, Anderson & Carlson (1980)
MISSISSIPPIAN
MADISON GROUP
LODGEPOLE LIMESTONE
MADISON GROUP
LODGEPOLE FORMATION
Woodhurst Limestone
Paine Member
MADISON GROUP
SOURIS VALLEY BEDS
Whitewater Lake
Upper
Lower
Virden
Upper
Lower
Scallion
Routledge Shale
MADISON GROUP
LODGEPOLE FORMATION
UPPER
LOWER
Whitewater Lake
Upper
Lower
Virden
Upper
Lower
Scallion
Routledge Shale
MADISON FORMATION
BOTTINEAU INTERVAL
MADISON GROUP
LODGEPOLE FORMATION
BOTTINEAU INTERVAL
Flossie Lake
Whitewater Lake
Upper
Lower
Virden
Upper
Lower
Scallion
Carrington Shale

Fig. 1 - Regional nomenclature for the Lodgepole Formation.

The shelf facies consists of cream to grey, fossiliferous and oolitic limestone, which is generally divided into several marker-defined units (Fig. 1; Edie, 1958; McCabe, 1959). These "workable" units represent several depositional environments that were present along the basin margin during Early Mississippian time (Heck, 1978). Along the eastern margin of the Williston Basin, the Lodgepole unconformably overlies the Devonian Three Forks, Birdbear, and Duperow, and the Ordovician Red River Formations.

NORTHWESTERN NORTH DAKOTA

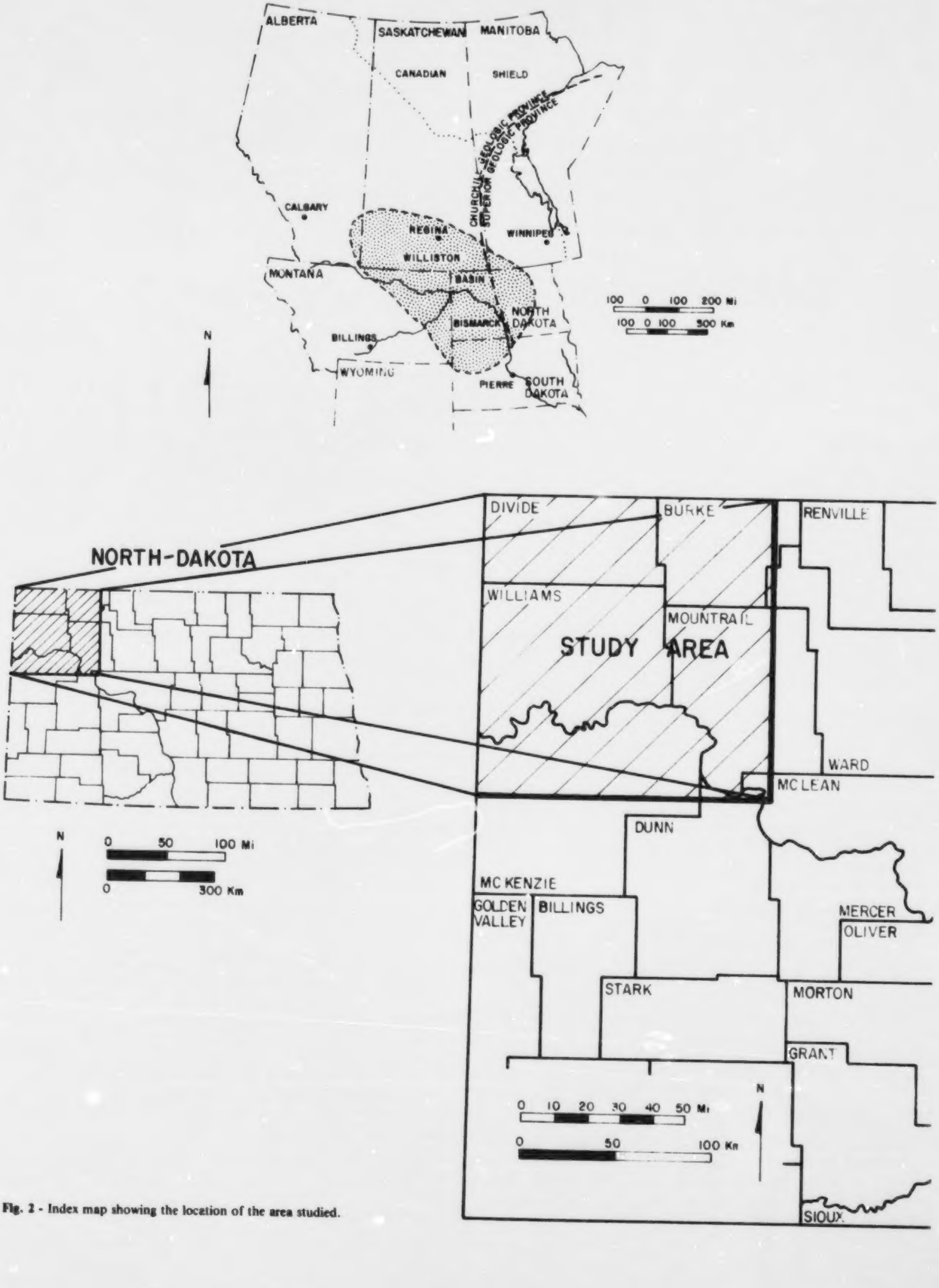
The present area of study includes the northwestern portion of North Dakota (Fig. 2).It represents the central basin facies of the Lodgepole Formation (Carlson and Anderson, 1966; Heck, 1978). Only one well in the study area was cored (Dakamont-Jacobsen #1); therefore, the lithology described in this report is based primarily on the study of core chips from the Dakamont-Jacobsen #1 and from samples from three other wells. Carlson and Anderson (1966) divided the Lodgepole into three informal subintervals; termed, in ascending order, L1, L2, and L3. These subintervals correspond to the lower Lodgepole, the carbonate unit, and the upper Lodgepole subintervals (Fig. 3).

LOWER LODGEPOLE

The lower Lodgepole (L1) ranges in thickness from 5 metres (15 ft) in the Carter-D. Moore #1 (T.163N., R.102W., 7 NWNE) to 219 metres (717 ft) in the Texaco-Keogy #4 (T.151N., R.95W., 5 NWSW; Fig. 4). This subinterval is generally described as brownish grey to medium dark grey, very fine- to fine-grained, argillaceous limestone. It is tight, dense, and has shale stringers. Log characteristics of the lower Lodgepole give indications that sedimentaion wasy cyclical in nature. Similar "repeat" sections appear as the subinterval thickens (Figs. 5, 6, and 7). Cross section A-A' also shows that the thinning is from the top of the Bakken-basal Lodgepole and is probably due to non-deposition (Carlson and Anderson, 1966; this report).

CARBONATE UNIT

The second subinterval (L2) is the one that is the primary concern of this paper. This unit ranges in thickness from 0 to a maximum of 39 metres (128 ft) in the Conoco-Windfaldet #26-2 (T.163N., R.99W., 26 NESE; Fig. 8). The unit is a light brownish grey to dark grey, very fine-grained to microcrystalline limestone. It varies from a dense, light argillaceous limestone to a silty limestone and it can contain up to 30 per-


ALBERTA
SASKATCHEWAN
MANITOBA
CANADIAN
SHIELD
CHURCHILL GEOLOGIC PROVINCE
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REGINA
WINNIPEG
WILLISTON
BASIN
MONTANA
NORTH DAKOTA
BISMARCK
BILLINGS
WYOMING
PIERRE
SOUTH DAKOTA
100 0 100 200 Mi
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N
NORTH-DAKOTA
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DIVIDE
BURKE
RENVILLE
WILLIAMS
MOUNTRAIL
STUDY AREA
WARD
MC LEAN
DUNN
MC KENZIE
GOLDEN VALLEY
BILLINGS
MERCER
OLIVER
STARK
MORTON
GRANT
SIOUX
0 10 20 30 40 50 Mi
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Fig. 2 - Index map showing the location of the area studied.

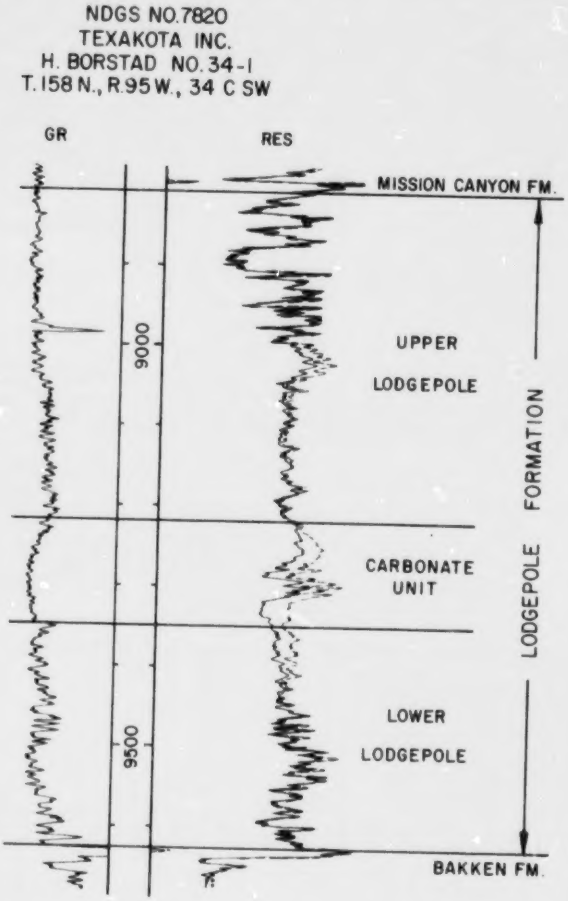


Fig. 3 - Type log showing the subintervals of the Lodgepole Formation used in this paper.

cent quartz sand. Samples analyzed by the scanning electron microscope show the presence of quartz, clay, dolomite, and calcite. Oil staining and healed fractures are present in some of the samples.

Log characteristics substantiate the sample descriptions suggesting a "clean" carbonate relative to the overlying and underlying argillaceous limestone. Two types of porosities are apparent from logs — a matrix porosity and a suggested fracture porosity (Fig. 9). It is impossible to determine the type of matrix porosity from logs. The fracture porosity is suggested by the "wash" on the caliper log and the corresponding static appearance on the resistivity log (Fig. 3). This is further substantiated from the core description of the Dakamont-Jacobsen #1 Well where numerous, tight, closed, vertical fractures were reported. Figure 9 shows the approximate distribution of these types of porosities, determined from logs.

Areal distribution of the carbonate unit is shown on figure 8 with the unit pinching out to the east and south. A similar carbonate unit occurs in Billings Country, North Dakota. This carbonate unit is separate from the one previously discussed and is stratigraphically lower.

UPPER LODGEPOLE

The upper Lodgepole ranges in thickness from 58 to 169 metres (190 to 550 ft; Carlson and Anderson, 1966). Log characteristics indicate a highly variable unit which has generally been described as light brownish grey to medium brownish grey, dense, microcrystalline limestone.

STRUCTURE

Major structural features, including the Nesson and Antelope anticlines, smaller associated folds, and the western Nesson fault are apparent on structure maps on the top of the Bakken Formation (Fig. 10) and on the top of the carbonate unit (Fig. 11). Both structure maps also show the present basin configuration.

Isopach maps of the lower Lodgepole (Fig. 4) and the carbonate unit (Fig. 8) show no apparent thinning in the area of the Nesson and Antelope anticlines, suggesting that these structures were inactive at the time these units were deposited; the Lodgepole also shows no thinning over these structures (Heck, 1978). A northern source for the sediments of the Lower Lodgepole and carbonate unit is also indicated from the isopachs. This suggests that the reorientation of the seaways from the Elk Point basin to the Central Montana trough did not occur during Bakken sedimentation, as previously thought, but rather somewhat later, possibly as late as middle Lodgepole (Early Mississippian) time (Carlson and Anderson, 1965; Bjorlie, 1979; Gerhard *et al.*, 1982).

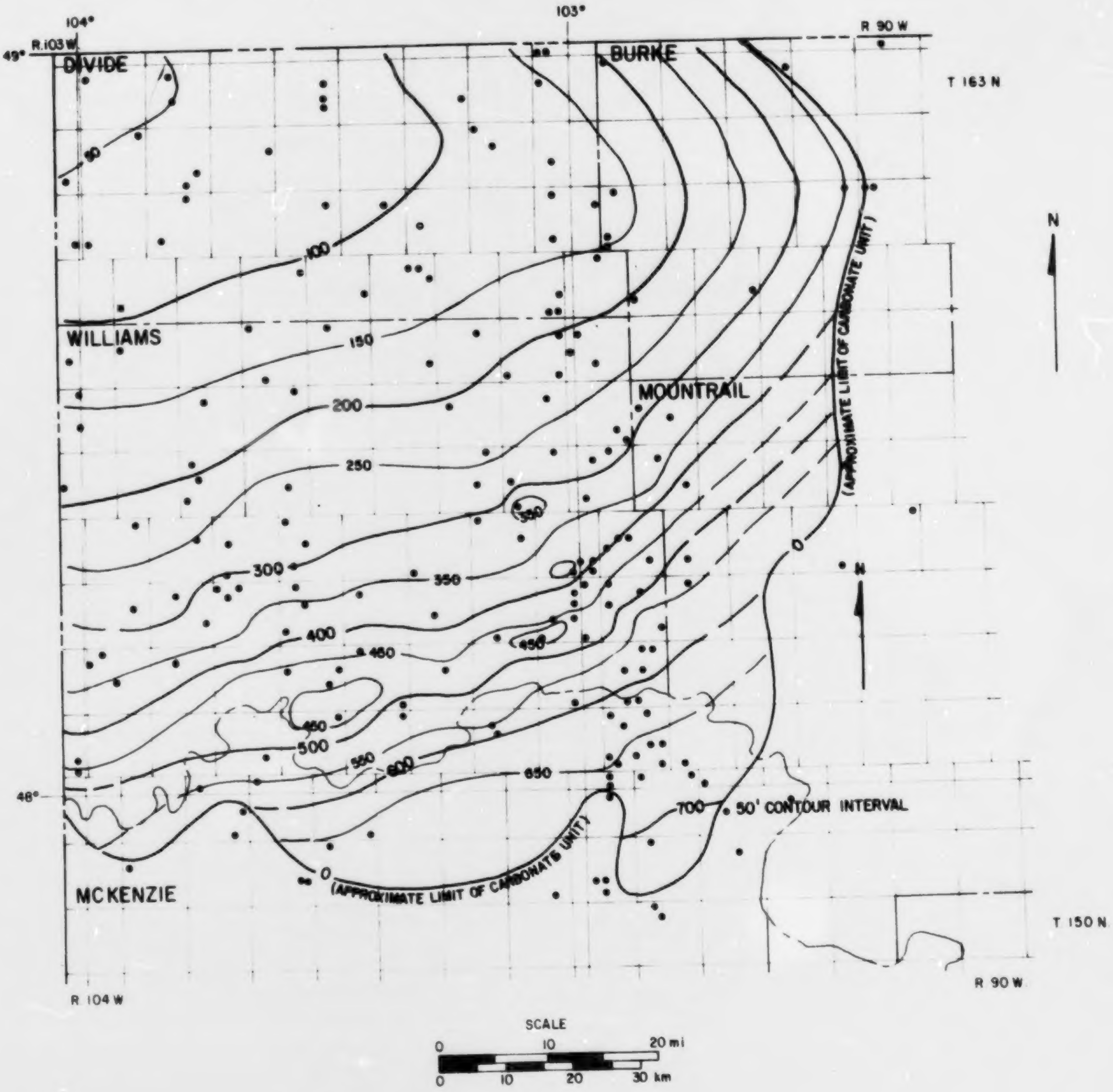
Another feature present in the isopach of the carbonate unit is a thin area with a northwest orientation suggesting a structural high was present at the time deposition. No evidence exists as to the nature of this structural feature. It may be correlated to the Central Plains Conductivity Anomaly which is probably a fracture or fold zone that is possibly a Proterozoic plate boundary (Alabia, Camfield, and Gough, 1975; Camfield and Gough, 1977). Another alternative is that it was a structure present for a short duration related to the Fromberg-Colorado-Wyoming shear zone described by Gerhard *et al.* (1982).

A map of the wells with a fractured carbonate unit (Fig. 9) show two dominant orientations. The first, a north-south strike, corresponds roughly to the strike of the western Nesson fault. The second set follows a northwest - southeast strike corresponding to the "thin" indicated by the carbonate unit isopach map (Fig. 9). Two areas of possible fracturing also exist to the northeast of the second set. Both fracture sets are ralted to movement that occurred after deposition. This is further substantiated by the absence of the western structure on present-day structure maps.

PETROLEUM POTENTIAL

Four wells in Williams County, three along the west side of the Nesson anticline and one in the isopach "thin" in the western portion of the county, have produced from the carbonate unit. The initial potentials of these wells are presented in Table 1. Perforated pay zones range from 2 to 15 metres (6 to 50 ft) with an average of 6 metres (20 ft). Perforations are usually located within the "fractured" zone; however, one well was producing from what appears to be matrix porosity rather than from fractures.

Staining was noted in samples of the carbonate unit from an additional well (a non-producer) by Carlson and Anderson (1966). Samples from the Hunt-Amerada-Pederson, Cater #1 Well were oil-stained, but the interval was never tested.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WILLIAMS
MOUNTRAIL
(APPROXIMATE LIMIT OF CARBONATE UNIT)
48°
50' CONTOUR INTERVAL
MCKENZIE
T 150 N
R 104 W
R 90 W
SCALE
0 10 20 mi
0 10 20 30 km

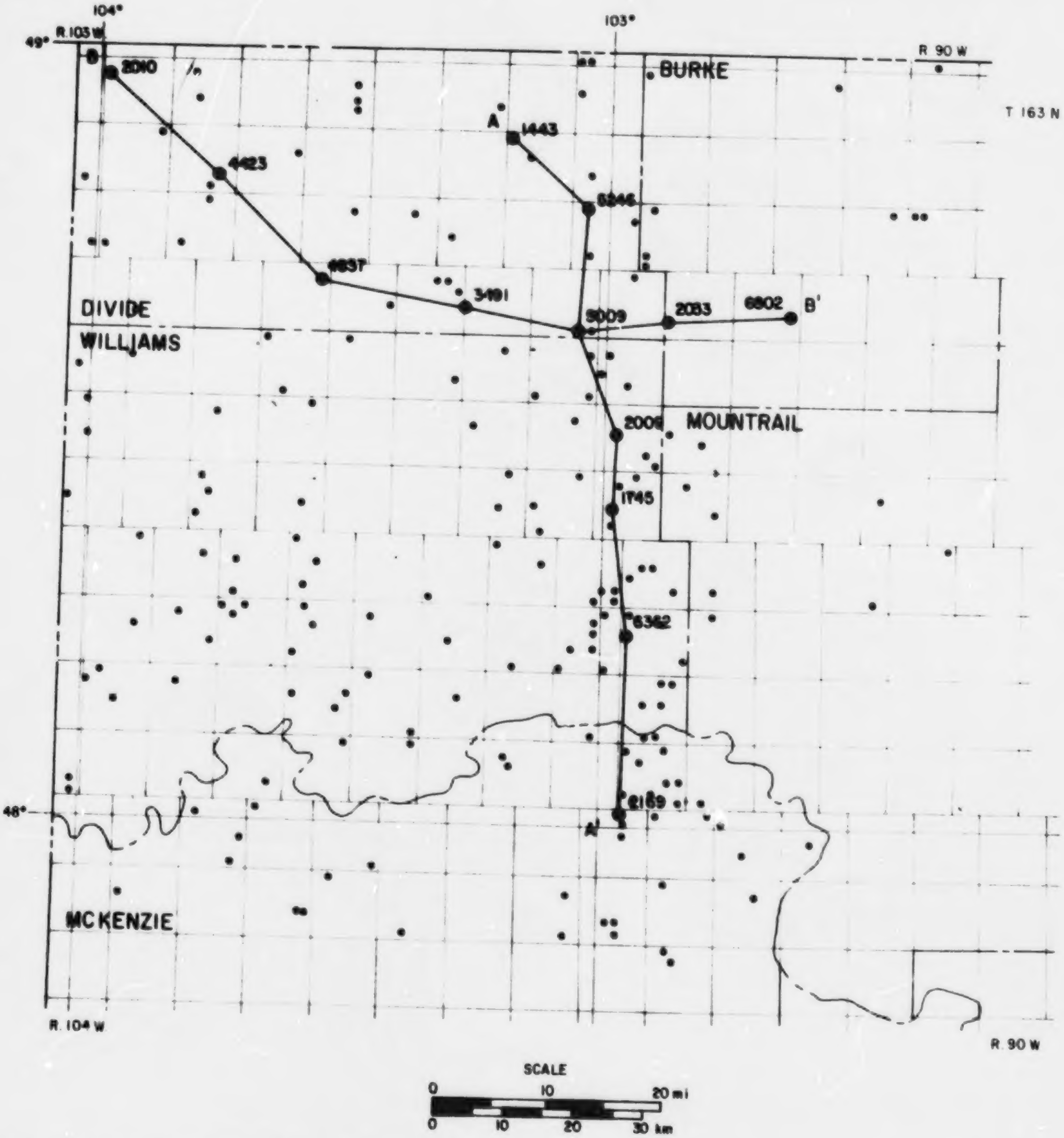
Fig. 4 - Isopach of the lower Lodgepole (L1) subinterval.

CONCLUSIONS

Structure and isopach maps of the Lodgepole reflect several significant facts. The Nesson and the Antelope anticlines were inactive during Lodgepole time; however, a western structure was prominent during the time of deposition of the carbonate unit (Fig. 8). Isopachs indicate that the source of the sediment was from Elk Point basin until at least middle Lodgepole time, and not from the Central Montana trough as was previously thought. The isopach maps also indicate a regression towards the Elk Point basin.

The relationship of the western structure to the Central Plains Conductivity Anomaly and a possible Proterozoic plate boundary or the Fromberg-Colorado-Wyoming shear zone can only be suggested.

Tectonic activity along the Nesson and Antelope anticlines and the western structure after Lodgepole time resulted in the fracturing of the carbonate unit. This unit has a history of or a potential for being a petroleum reservoir. It should probably not be considered as a prime objective; however, it should be kept in mind when drilling deeper prospects.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1745
6362
2169
A'
SCALE
0
10
20 mi
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10
20
30 km

Fig. 5 - Index map showing the location of cross sections A-A' and B-B'.

TABLE 1

N.D.G.S. Number Operator Well Name Location (Field)	Initial Potentials				
	Completion	BOPD	BWPD	G-O-R	Gravity
#3899 Calvert Drilling and Production Co. Cater #1 T.158N., R.95W., 28 NWNW (McGregor Field)	7-15-66	94	0	Not Reported	40°
#6789 Argonaut Energy Corp. Barkie #1 T.156N., R.103W., 23 SWSW (Bull Butte Field)	10-26-79	6	5	0	34.1°
#7820 Texakota, Inc. H. Borstad #34-1 T.158N., R.95W., 34 CSW (West Tioga Field)	11-13-81	27	4	2700:1	44°
#8039 Hunt Energy Corp. Olaf Serve #1 T.159N., R.97W., 10 SWNW (Cornith Field)	4-30-81	32	0	2500:1	35.5°

Table 1 - Initial potentials for wells which have produced from the carbonate unit.

ACKNOWLEDGMENTS

The authors would like to thank John P. Bluemle and Randolph B. Burke of the North Dakota Geological Survey and Richard D. LeFever of the University of North Dakota for their critical reviews of this manuscript. The manuscript was expertly typed by Connie Borboa of the North Dakota Geological Survey.

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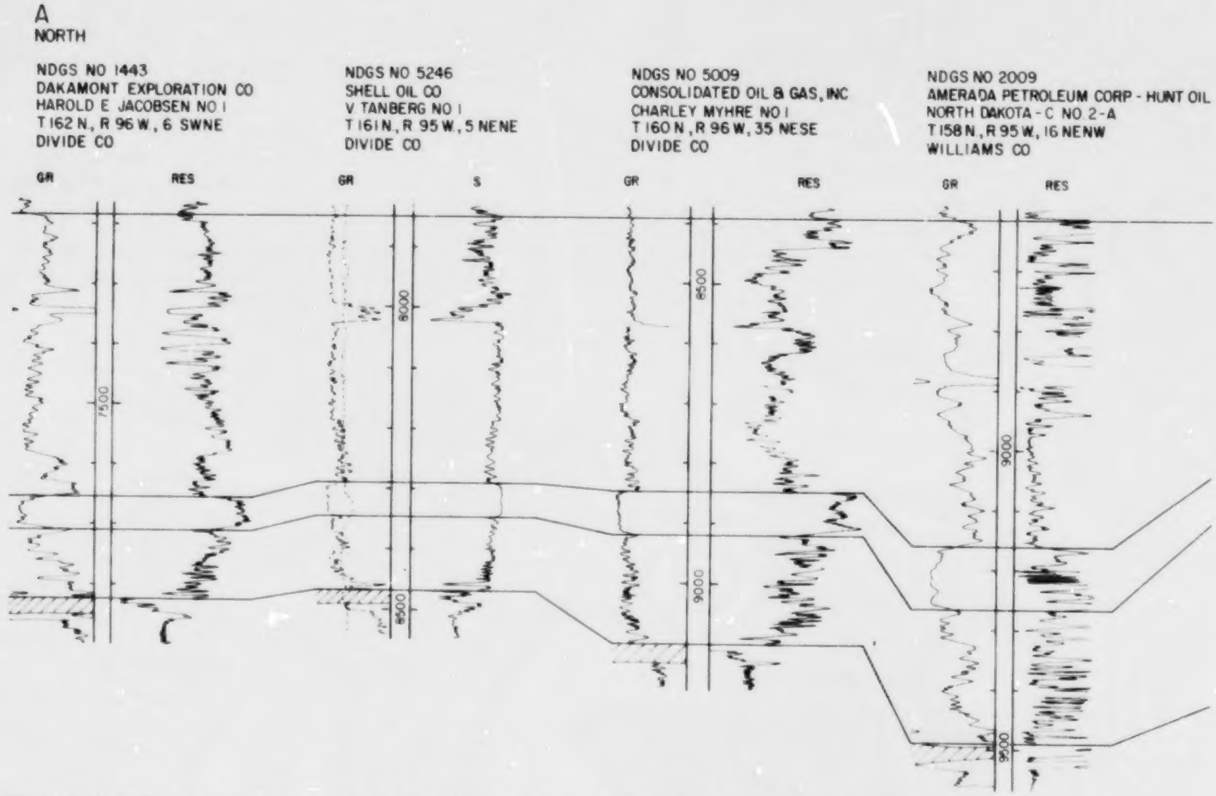


Fig. 6 - North-south cross section A-A' along the Nesson anticline showing the distribution of the Lodgepole subintervals.

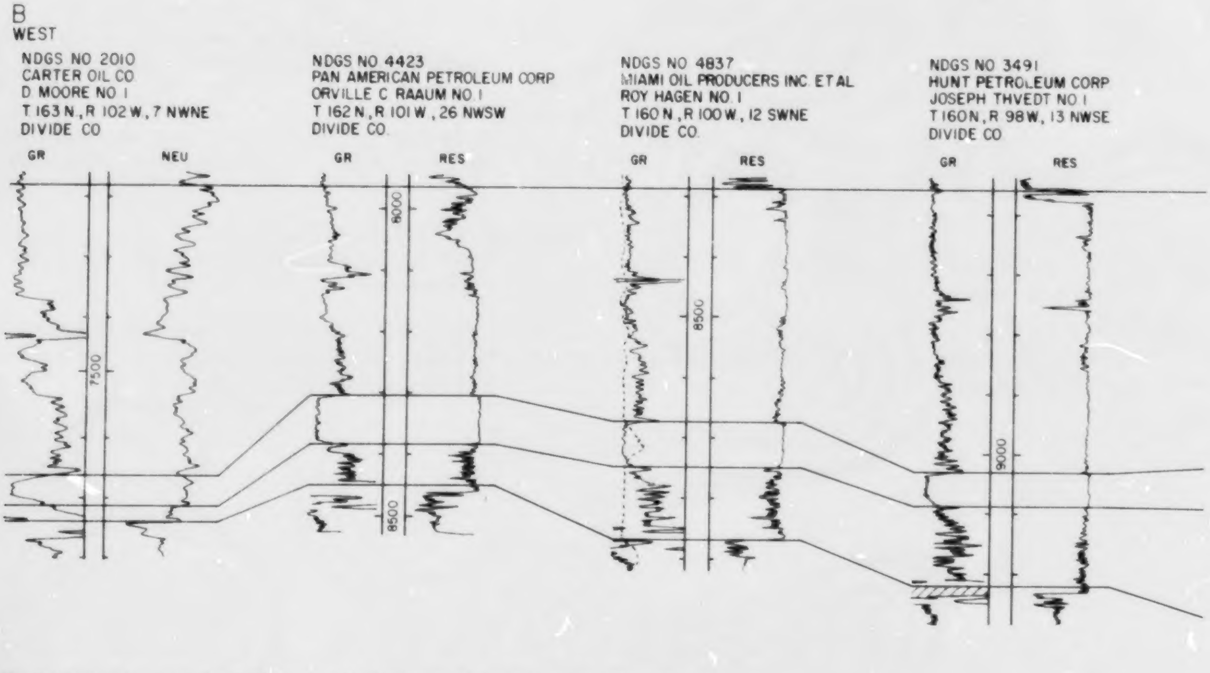
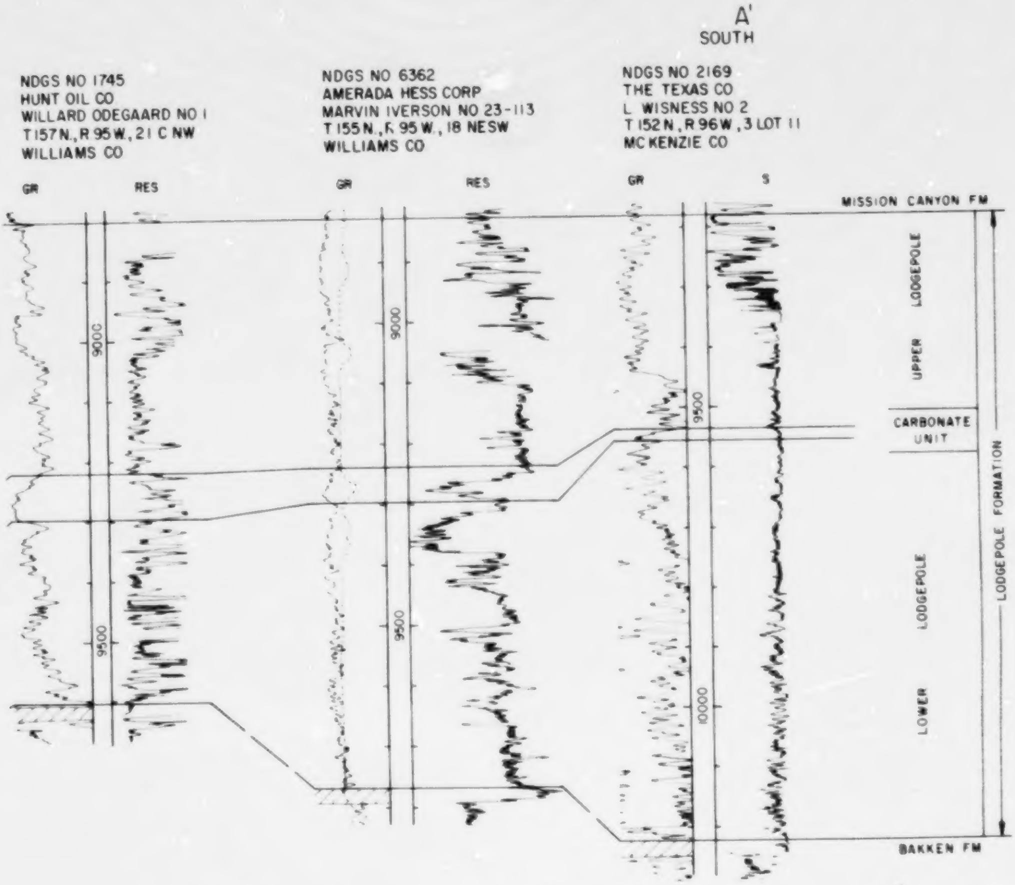


Fig. 7 - East-west cross section B-B' showing the distribution of the Lodgepole subintervals.


A'
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HUNT OIL CO
WILLARD ODEGAARD NO 1
T 157 N., R 95 W., 21 C NW
WILLIAMS CO
NDGS NO 6362
AMERADA HESS CORP
MARVIN IVERSON NO 23-113
T 155 N., R 95 W., 18 NESW
WILLIAMS CO
NDGS NO 2169
THE TEXAS CO
L WISNESS NO 2
T 152 N., R 96 W., 3 LOT 11
MC KENZIE CO
GR
RES
GR
RES
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S
9000
9500
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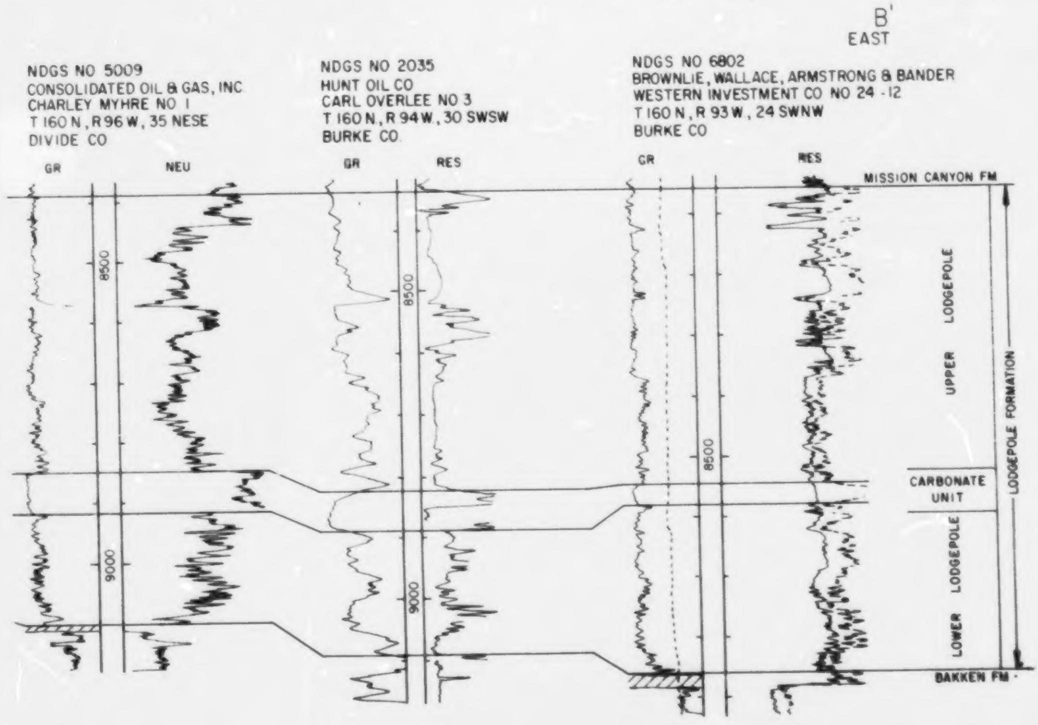
MISSION CANYON FM
UPPER LODGEPOLE
CARBONATE UNIT
LOWER LODGEPOLE
LODGEPOLE FORMATION
BAKKEN FM


B'
EAST
NDGS NO 5009
CONSOLIDATED OIL & GAS, INC
CHARLEY MYHRE NO 1
T 160 N, R 96 W, 35 NESE
DIVIDE CO
NDGS NO 2035
HUNT OIL CO
CARL OVERLEE NO 3
T 160 N, R 94 W, 30 SWSW
BURKE CO
NDGS NO 6802
BROWNLIE, WALLACE, ARMSTRONG & BANDER
WESTERN INVESTMENT CO NO 24-12
T 160 N, R 93 W, 24 SWNW
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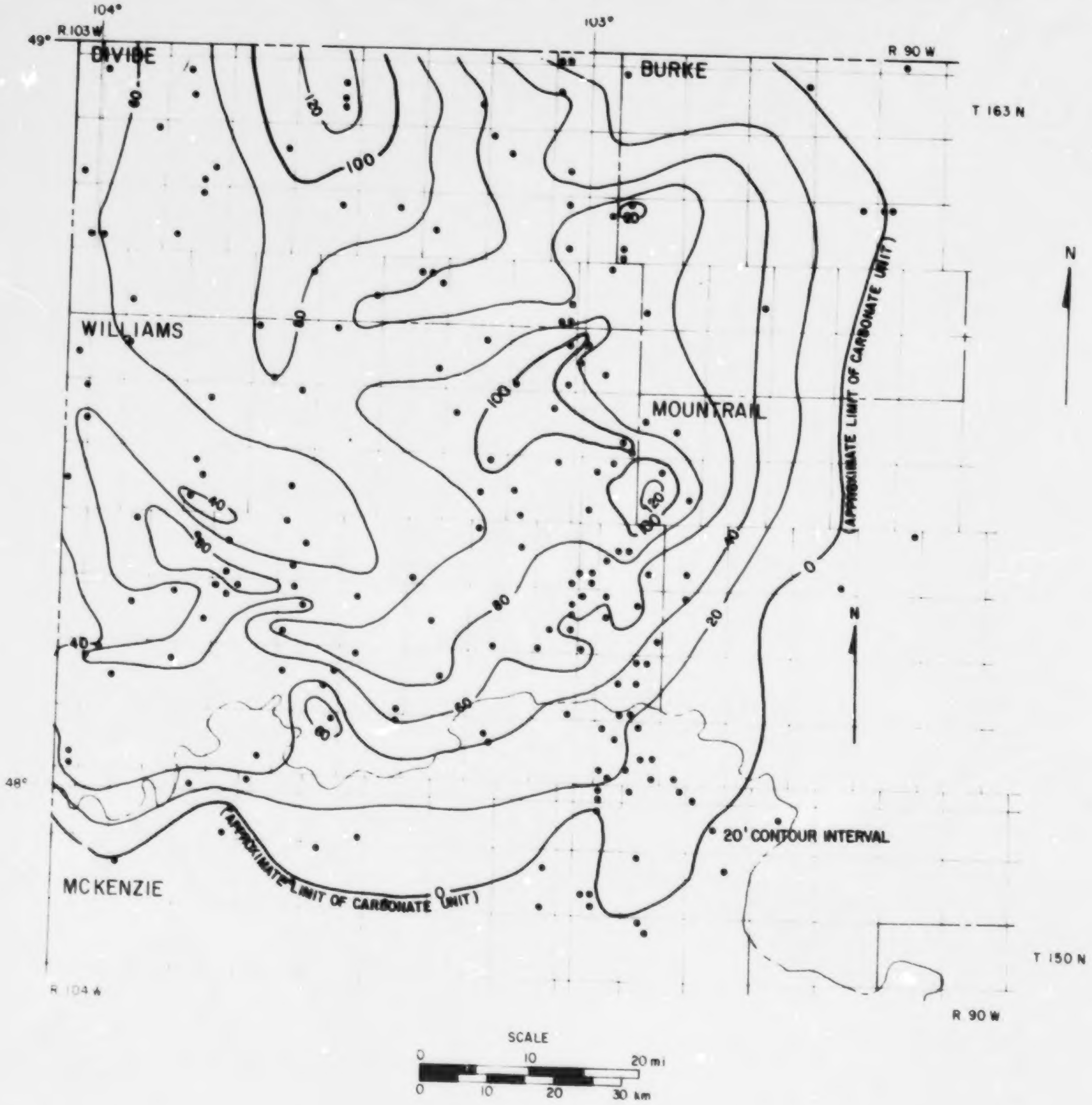
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Fig. 8 - Isopach of the carbonate unit (L2) subinterval. Thin area referred to in text is located between T.156N. and T.159N. and R.100W. and R.104W.

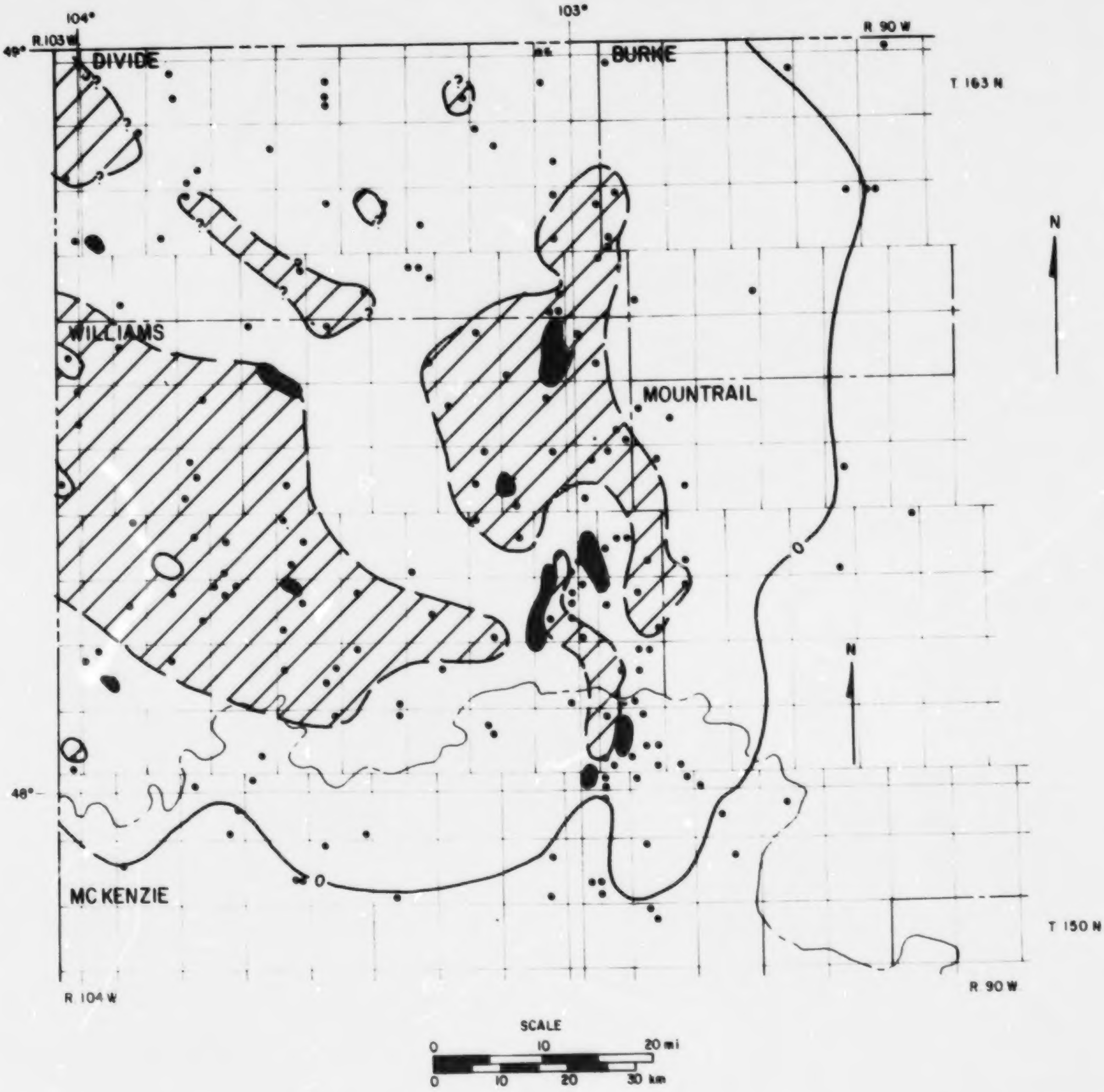
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Fig. 9 - Map showing the distribution of porosity types for the carbonate unit based on log characteistics. Shaded pattern indicates areas of matrix porosity. Line pattern indicates areas of possible fracture porosity.
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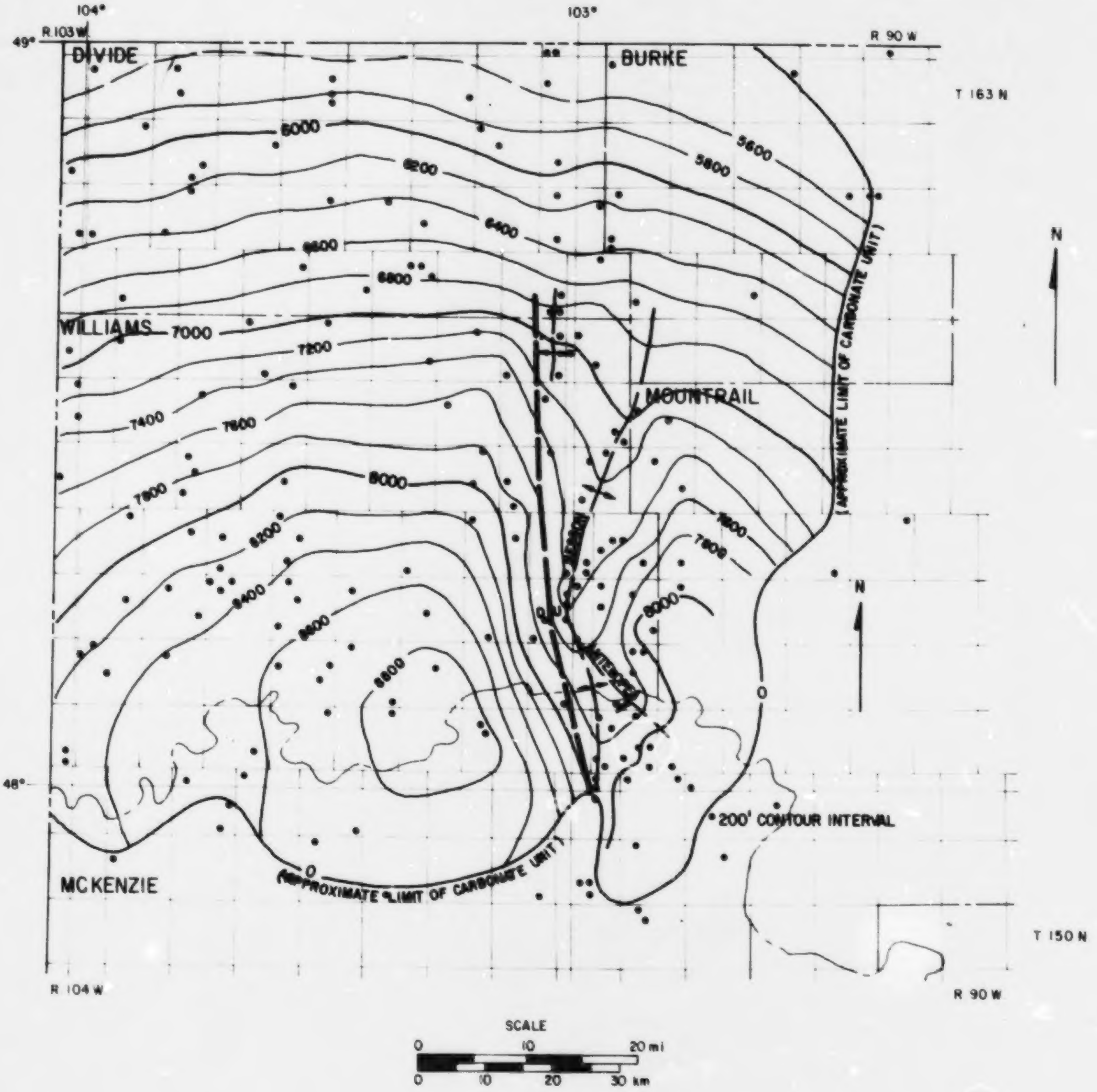
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Fig. 10 - Structure map on the top of the Bakken Formation.

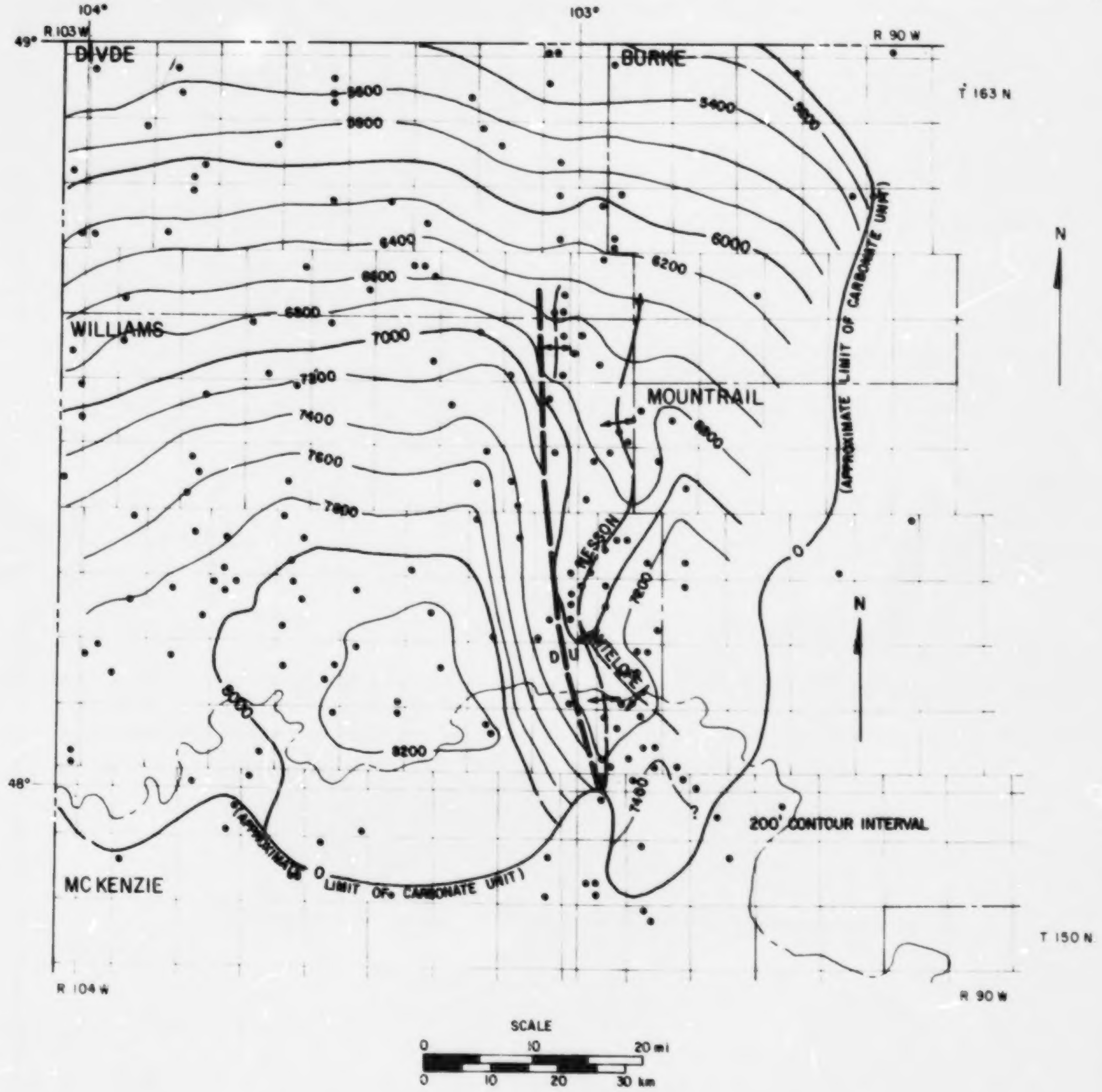
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Fig. 11 - Structure map on the top of the carbonate unit.

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PROCESSES OF DOLOMITIZATION — IMPORTANT FACTORS INFLUENCING PORE GEOMETRY AND RESERVOIR QUALITY IN MISSISSIPPIAN INNER SHELF CARBONATES OF SOUTHEASTERN SASKATCHEWAN

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Department of Geology
University of Regina
Regina, Saskatchewan S4S 0A2

ABSTRACT

The origin of the dolomites that form hydrocarbon reservoirs in inner shelf lime mudstones and wackestone of the Mississippian Midale and Ratcliffe Beds of southeastern Saskatchewan is not clearly understood. However, studies of the geometry of pore systems using capillary pressure mercury injection analyses supplemented by scanning electron microscopy aid elucidation of the processes that created the dolomitized reservoir rocks.

There is fairly good evidence that entry pressures obtained from capillary pressure mercury injection analyses are markedly influenced by the "calcareousness" of the carbonate reservoir rock; the greater the proportion of dolomite present, the lower the entry pressure. In addition, it has been shown that the best dolomite reservoir is one in which 75% to 90% of the rock has been dolomitized (inhibition boundary stage of crystal growth). When the degree of dolomitization increases beyond 90% the dolomite cyrstals enter a compromise boundary stage of growth, resulting in a reduction of pore volume and permeability. Attainment of the inhibition boundary stage is not sufficient to produce a good reservoir; it must be accompanied by dissolution of the remnant host rock, creating porosities ranging from 25% to 38% and permeabilities on the order tens of millidarcies. An additional factor that creates good reservoir rock in the inhibition boundary stage of crystal growth is the uniform size of crystals and pore throats, easily recognized on capillary pressure mercury saturation plots.

The most likely dolomitizing mechanism by which both inhibition boundary stage and remnant host rock dissolution could be facilitated is the mixing zone process. Fresh meteoric waters capable of dissolving the remnant host rock would enter the dolomitized rock proceeding the passage of the mixing zone through it. In contrast, reflux dolomitization would be more likely to cause either a compromise boundary stage of dolomitization or produce a calcareous dolomite.

INTRODUCTION

Over the past eight years the senior author and a number of graduate students in the Department of Geology, University of Regina, have been involved in investigations into the nature of pore systems in a variety of hydrocarbon reservoirs in the carbonate rocks of the Mississippian System of southeastern Saskatchewan. The studies have been threefold in nature, including microfacies analyses of the rocks in the field areas, pore geometry studies employing mercury injection capillary pressure (MICP) techniques, and an interpretation of the influence of diagenesis on the porosity as determined from light and scanning electron microscopy. To date, fairly detailed investigations have been completed on four fields and one of the present authors (JBB) is examining three other fields, Flat Lake, Lake Alma, and Oungre (Fig. 1). All of the fields studied present a fairly broad cross section of reservoir rock types with some distinct differences in pore geometry characteristics. In several of the fields, most production is from dolomitized lime mudstones or skeletal and peloidal wackestones. These rocks exhibit marked variations in the degree of dolomitization, and hence, in reservoir quality. It appears that the extent of dolomitization could be related to the mechanism of dolomitization.

The fields considered in this paper include: Flat Lake, Lake Alma and Oungre, all producing from the Ratcliffe Beds, as well as Benson and Glen Ewen producing from the Midale Beds (Fig. 1).

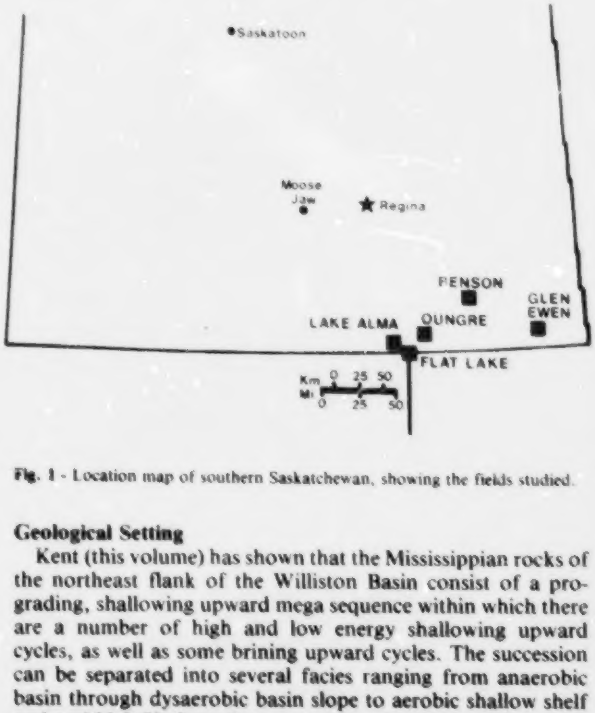

Fig. 1 - Location map of southern Saskatchewan, showing the fields studied.

Geological Setting

Kent (this volume) has shown that the Mississippian rocks of the northeast flank of the Williston Basin consist of a prograding, shallowing upward mega sequence within which there are a number of high and low energy shallowing upward cycles, as well as some brining upward cycles. The succession can be separated into several facies ranging from anaerobic basin through dysaerobic basin slope to aerobic shallow shelf and peritidal. Hydrocarbon reservoirs are commonly found in partly or totally dolomitized inner shelf lime mudstones and wackestones or in the shelf marginal and shelf crestal skeletal and oolitic grainstones, packstones, wackepackstones, and wackestones. The shelf rocks constitute the subtidal portion of the shallowing and brining upward cycles, each of which terminates with an interval of either displacive or layered anhydrite (Kent, 1984). The anhydritic intervals are important, as well, because they form part of the seals to hydrocarbon reservoirs.

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The Mississippian succession in southeastern Saskatchewan is progradational, and this has been instrumental in creating a sequence of isochronous marker-defined units (Table 1). Each unit may include several facies and the same facies may be present in vertically stacked units. Postdepositional tilting of the flanks of the Williston Basin and truncation of the strata at the margins have resulted in subcropping traces of the marker-defined units at the pre-Mesozoic unconformity. It is along these subcrop trends that most Mississippian oilfields are located.

CHARACTERISTICS OF THE RESERVOIR ROCKS

Lithology

The results of this investigation are taken from five field areas (Fig. 1) and two marker-defined units (Table 1), involving some distinct differences in the lithologies and pore systems of the reservoirs.

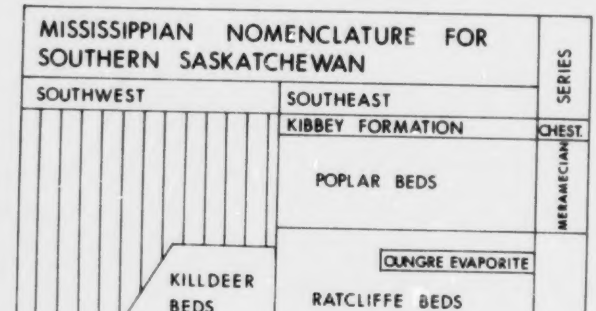
MISSISSIPPIAN NOMENCLATURE FOR SOUTHERN SASKATCHEWAN
SERIES
SOUTHWEST
SOUTHEAST
KIBBEY FORMATION
CHEST.
POPLAR BEDS
MERAMECIAN
OUNGRE EVAPORITE
KILLDEER BEDS
RATCLIFFE BEDS
MIDALE EVAPORITE
MIDALE BEDS
FROBISHER EVAP.
HASTINGS EVAPORITE
FROBISHER BEDS
WINLAW EVAPORITE
OSAGEAN
STRATHALLEN BEDS
KISBEY SANDSTONE
GAINSBOROUGH EVAP.
ALIDA BEDS
TILSTON BEDS
"A" MARKER
SOURIS VALLEY BEDS
KINDERHOOKIAN
BAKKEN FORMATION
BAKKEN FORMATION

Table 1 - Stratigraphic nomenclature.

Smith (1980) and Leibel (1982) have shown that in the Benson Field production is from three intervals: one near the base of the Midale carbonate unit immediately adjacent to the Frobisher Evaporite; the second and most productive zone lies at the approximate middle of the Midal carbonate; and the third is subjacent to the Midale Evaporite (Table 1). For the most, part each reservoir rock is a partially or totally dolomitized lime mudstone, skeletal-peloidal wackestone or wackepackstone, the latter being the least common. The degree of dolomitization is particularily low in the upper and the lower producing zones. These rocks are not only more calcareous, but they are also restricted in areal extent. By contrast, the middle zone is fairly intensely dolomitized and relatively widespread. In fact, dolomitization in the middle interval appears to have reached, for the most part, the inhibition crystal growth stage (Wardlaw, 1979). The high quality of the reservoir rock, as indicated by porosity, permeability and MICP parameters, appears to be due to enhancement of porosity by dissolution of remnant host rock, a process recognized as a common cause of enhanced dolomite porosity (Wardlaw, 1979).

Walters (1982) also recognized three units in the Midale carbonate of the Glen Ewen Field. The upper and lower units are the most variable lithologically, ranging from lime mudstones to wackepackstones and locally, packstones. Allochems are mainly pellet material that in thin section appear as micritized fossils particles. In contrast, the middle unit is generally a microsucrosic dolomite that is somewhat argillaceous. Neither the upper nor the lower unit shows a high degree of dolomitization; in fact, SEM photomicrographs (Figs. 2, 3) show the distribution of dolomite crystals to be extremely sporadic and much of the host rock appears to consist of unaltered 1 to 4 μm micrite (Fig. 3). The finely crystalline rock appears to be in its original state and it has not been affected by neomorphic processes. In places dolomitization of the Midale carbonate has been fairly intensive (Fig. 4). Even at that, the MICP curve (Fig. 5) for this specimen shows only a fair degree of uniformity of pore throat sizes (as indicated by the slope of the curve). It is possible that patches of micrite may influence the uniformity of pore throat sizes, indicating that the specimen may not be as extensively dolomitized as suggested by the scanning electron micrograph (Fig. 3).

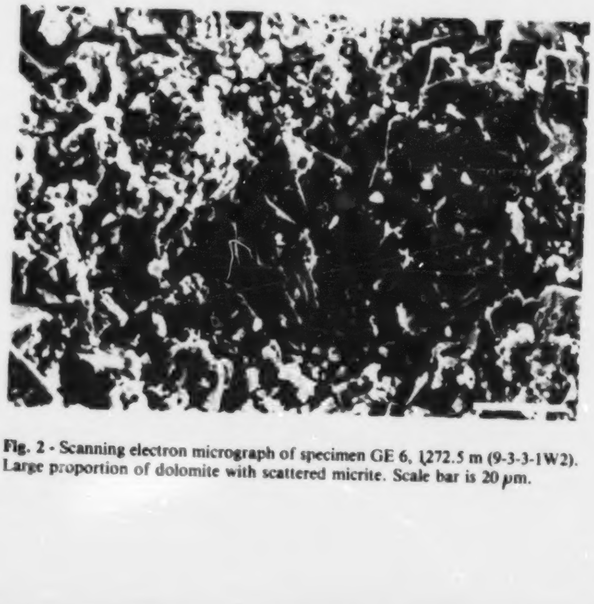

Fig. 2 - Scanning electron micrograph of specimen GE 6, 1272.5 m (9-3-3-1W2). Large proportion of dolomite with scattered micrite. Scale bar is 20 μm.

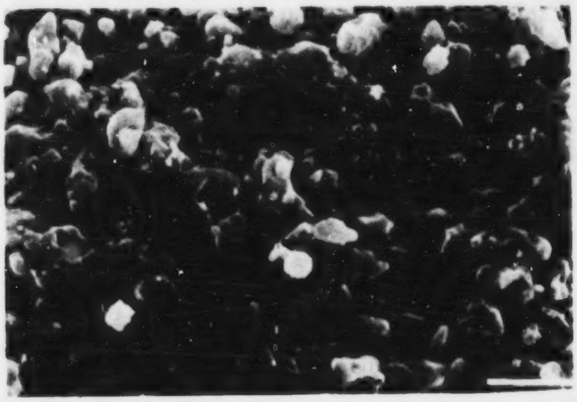

Fig. 3 - Scanning electron micrograph of specimen GE 4, 1319.5 m (9-27-2-1W2). Unaltered micrite. Scale bar is 4 µm.

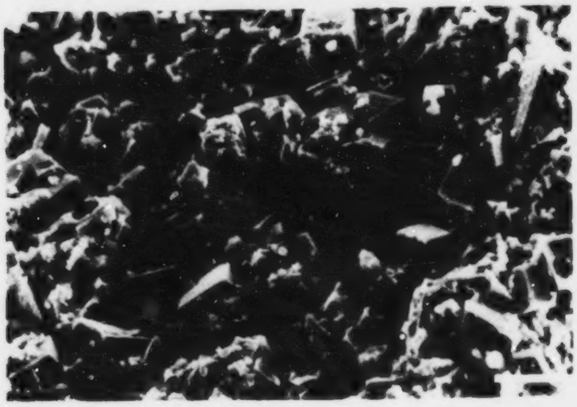

Fig. 4 - Scanning electron micrograph of specimen GE 10, 1289.3 m (3-21-3-1W2). Fairly intense dolomitization, a small amount of micrite. Scale bar is 20 µm.

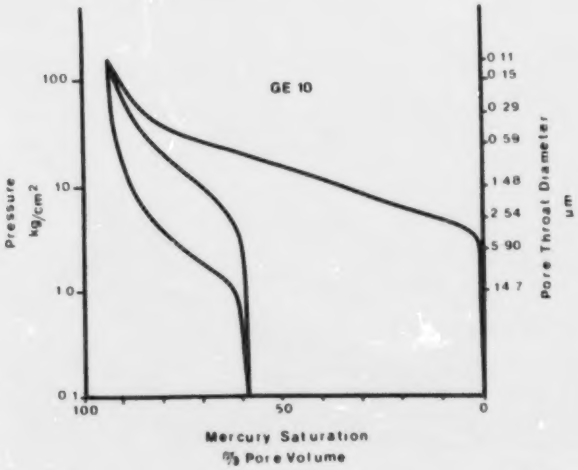

Fig. 5. - Mercury injection capillary pressure curve of specimen GE 10.

Although all three units in Glen Ewen have been perforated in parts of the field, much of the production is from the middle and upper units, neither of which exhibits highly favourable reservoir parameters. Magas (1960) recorded a net porosity of 13.7% and a permeability range of 1 to 10 md for nearly two-thirds of the net pay. MICP analyses of 20 samples from the two main producing intervals show a similar range of porosities and permeabilities, whith average ejection efficiencies in the range of 29% to 36%. Despite the rather low porosities and permeabilities, the ejection/reinjection hysteresis curves (Figs. 5, 6) suggests that the reservoir rocks are readily capable of yielding hydrocarbons (Kent *et al.*, 1982).

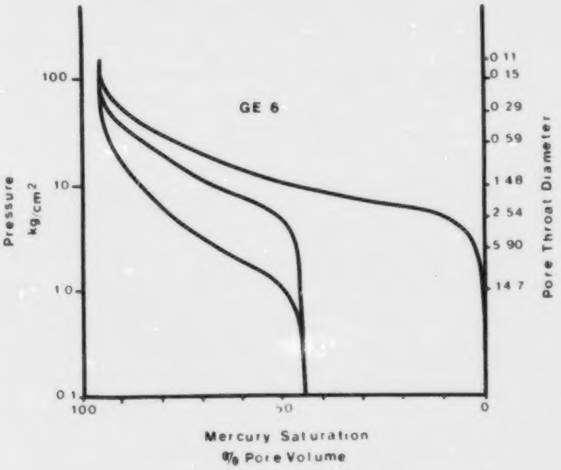

Fig. 6 - Mercury injection capillary pressure curve of specimen GE 6.

In the Oungre, Flat Lake and Lake Alma Fields production is from the Ratcliffe Beds. At Lake Alma and Oungre, the reservoir is in carbonate strata of the Oungre zone (Table 1), that lies between the Midale and Oungre Evaporites (Fuzesy, 1960, 1973). The producing interval at Flat Lake is in the upper Ratcliffe, above the Oungre Evaporite (Table 1). Dolomitized micritic rocks constitute much of the reservoir at Oungre, as exemplified by the scanning electron micrograph and MICP curve of specimen 0-3 (Figs. 7, 8). Both figures illustrate classic dolomite porosity characteristics. In contrast, the degree of dolomitization decreases from Flat Lake to Lake Alma: at Flat Lake the reservoir is variably dolomitized (Figs. 9, 10, 11) and at Lake Alma it is mainly a calcium carbonate rock with only slight amounts of dolomite. Figure 12 shows that parts of the lithologic sequence at Lake Alma consists of oolitic-peloidal packstone to wackestone.

Nature of the Pore Systems

MICP analyses can be employed to illustrate some significant differences in the pore systems of these fields and to speculate on the influence these differences have on the productivity of the reservoirs. Kent *et al.* (1982) showed that for hydrocarbon producing carbonate rocks, only three categories of porosity need be considered. They proposed that the categories be defined as intercrystal, cavity and mixed (a combination of the first two categories). These subdivisions cover a wide range of carbonate rock types. Intercrystal includes dolomites, sparry calcite-cemented packstones and grainstones, micrites and those carbonates that have been

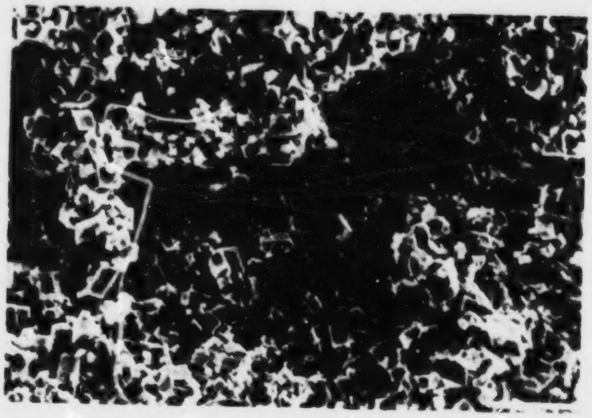

Fig. 7 - Scanning electron micrograph of specimen 0 3, 1847.88 m (9-19-2-14W2). Intense dolomitization, most remnant micrite removed by dissolution. Scale bar is 40 μm.

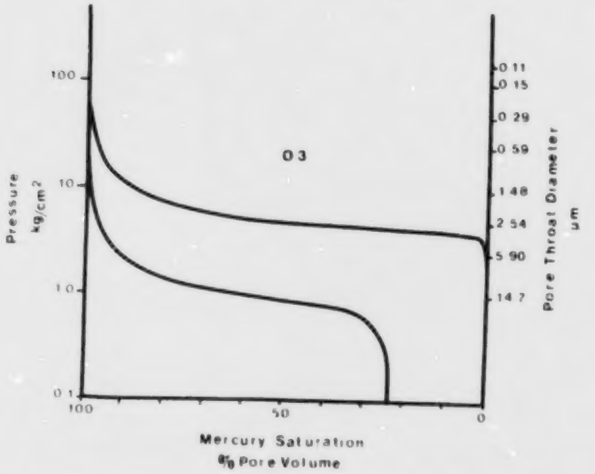

Fig. 8 - Mercury injection capillary pressure curve of specimen 0 3.

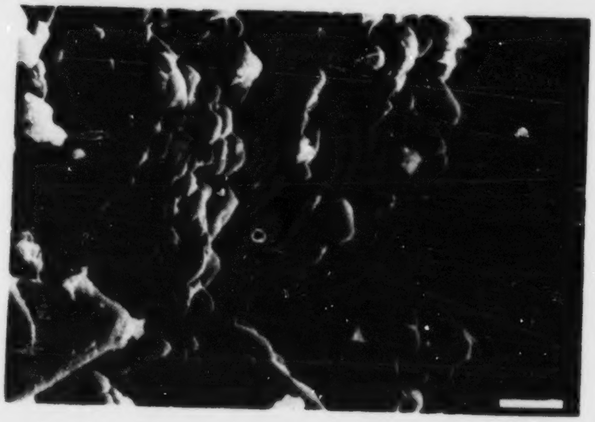

Fig. 9 - Scanning electron micrograph of specimen FL 6, 1975.06 m (12-22-1-16W2). Micritic limestone in part altered to microspar. Scale bar is 5 μm.

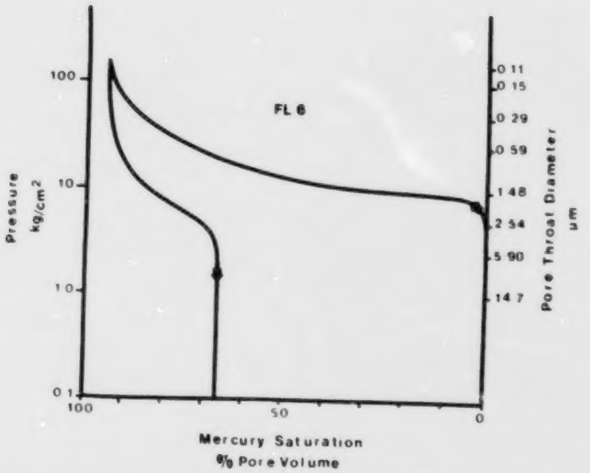

Fig. 10 - Mercury injection capillary pressure curve of specimen FL 6.

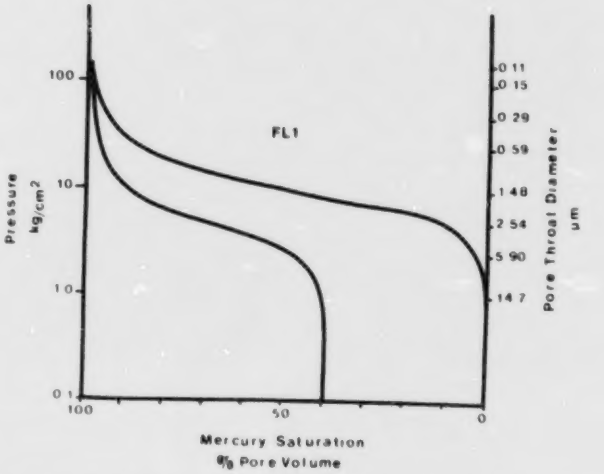

Fig. 11 - Mercury injection capillary pressure curve of specimen FL 1, 1952.94 m (10-4-1-16W2).

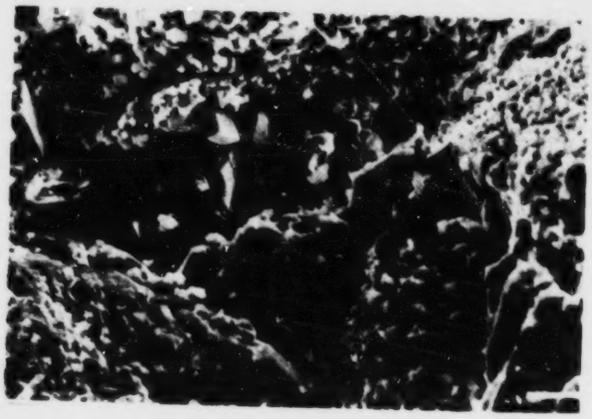

Fig. 12 - Scanning electron micrograph of specimen LA 1, 1981.0 (2-29-1-17W2)m. Oolitic and peloidal packstone/wackestone. Note dolomite and microspar in interstices. Scale bar is 10 μm.

diagenetically altered to micrites, microspar or pseudospar. Mixed includes dolomites in which cavities have been formed by dissolution of remnant host sediment or removal of allochems, as well as packstones and grainstones in which some of the cement has been dissolved. Cavity is created by the total removal of interstitial cement in grainstones or by the dissolution of allochems in neomorphosed micritic rocks. The categories can be fairly easily recognized in MICP analyses by the shapes of the capillary pressure curves. Akhurst (1984) has shown that a finer subdivision can be accomplished within a specific porosity category by visually comparing MICP curve shapes. In addition, Eriyagama (1983) showed that a finer subdivision can be effected through multivariate analysis of specific MICP values including porosity, permeability, ejection efficiency, entry pressure, unsaturated pore volume, and uniformity of pore throat sizes as interpreted from the standard deviation of pore throat diameters. The senior author has found that a Cosine θ variant analysis of the above MICP values from the Benson Field, combined with a dendrogram plot of the significance levels obtained from the variant analysis can be an extremely valuable tool in making distinctions between good and poor reservoir rocks (Kent, D. M., unpublished data). Thus there are a variety of approaches to evaluation of pore systems employing MICP data.

Based on work by Wardlaw and Cassan (1979), Kent *et al.* (1982) showed that the best non-wetting fluid yield could be expected from intercrystal or mixed reservoirs with micro-cavities and high porosity and permeability. By contrast, mixed reservoirs with meso-cavities or purely cavity porosity have considerably lower withdrawal efficiencies, and thus potential fluid yields.

Figures 5, 6, 8, 10, 11, 13, and 14 illustrate typical MICP curves from Glen Ewen, Oungre, Lake Alma, and Flat Lake. When compared to MICP curves presented by Kent *et al.* (1982), these indicate that porosity in the four fields is mainly intercrystal, possibly with some mixed as shown by Fig. 13. Leibel (1982) found that increased entry pressures apparently reflect higher calcareous content (Fig. 16). The high entry pressure for many of the samples suggest that they are fairly calcareous. Thus Figures 9, 13 and 14 are fairly typical limestone curves; Figures 5, 6 and 10 are representative of dolomitic limestone; and Figures 8, 11 and 15 are typical dolomite curves, (in fact, any dolomite that has reached a stage of 70% to 90% dolomitization, such as that of Figure 17, should have a curve shape and MICP values similar to those of Figures 8, 11 and 15).

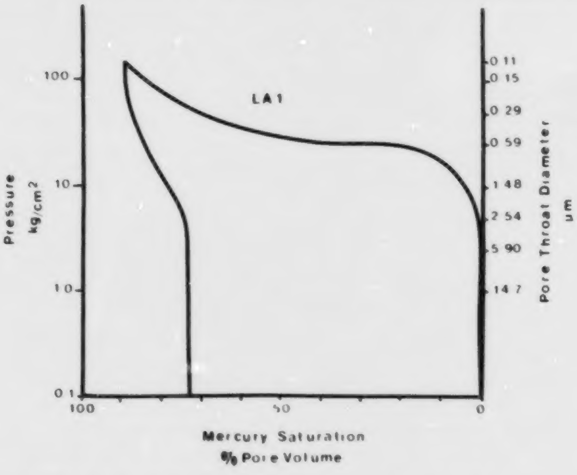

Fig. 13 - Mercury injection capillary pressure curve of specimen LA 1.

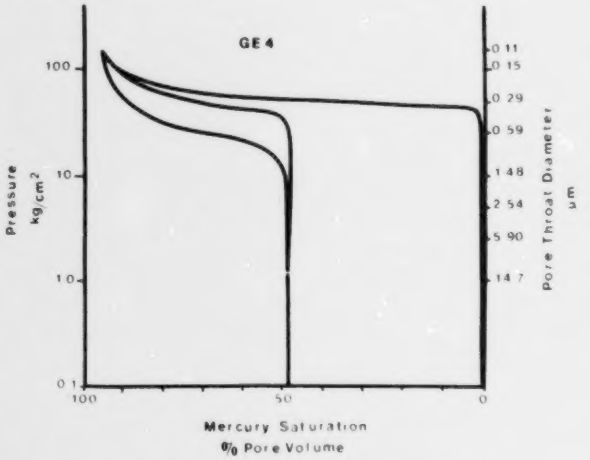

Fig. 14 - Mercury injection capillary pressure curve of specimen GE 4.

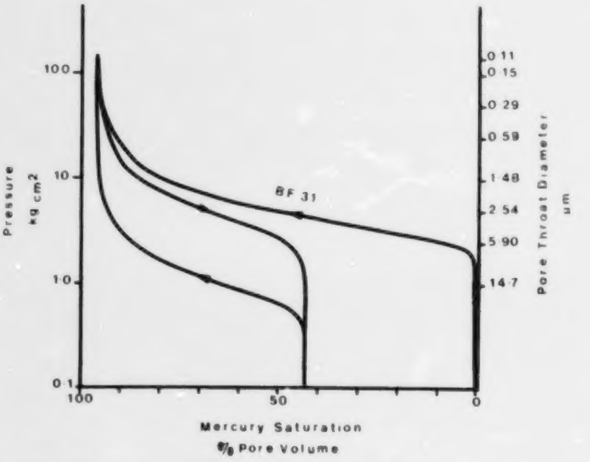

Fig. 15 - Mercury injection capillary pressure curve of specimen BF 31.

CALCAREOUSNESS AND MECHANISMS OF DOLOMITIZATION

Since the recognition of dolomite in Holocene carbonate sediments in the early 1960's, models based on such sediments have become important in identification of processes by which ancient rocks have been dolomitized. Morrow (1982) presented an excellent summary of various proposed models, placing them into three basic categories: 1) refluxion; 2) mixing zone; and 3) burial-compaction. In the Williston Basin, the refluxion hypothesis is favoured to explain dolomite reservoirs that immediately underlie anhydrites interpreted to be standing water evaporite deposits (layered or vertical crystal anhydrite) (Longman *et al.*, 1983; Hartling *et al.*, 1982). This process requires that dolomitizing magnesium rich brines percolate through the carbonate sediments beneath the evaporite ponds. This appears to be an acceptable means of explaining thin zones of dolomite subjacent to evaporitic intervals, but it is quite likely that such dolomitized layers would be fairly

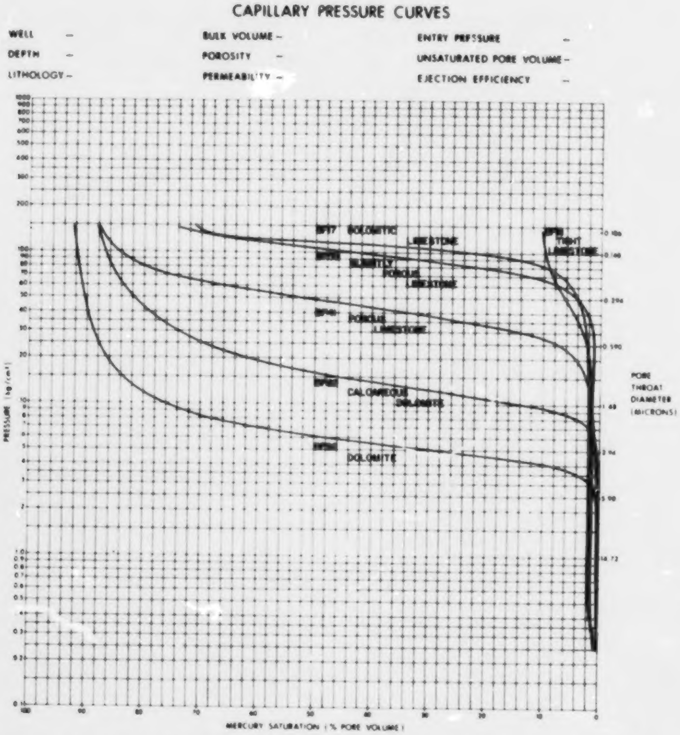

Fig. 16 - Mercury injection capillary pressure plots showing relationship between entry pressure and calcium magnesium carbonate content (from Leibel, 1982).

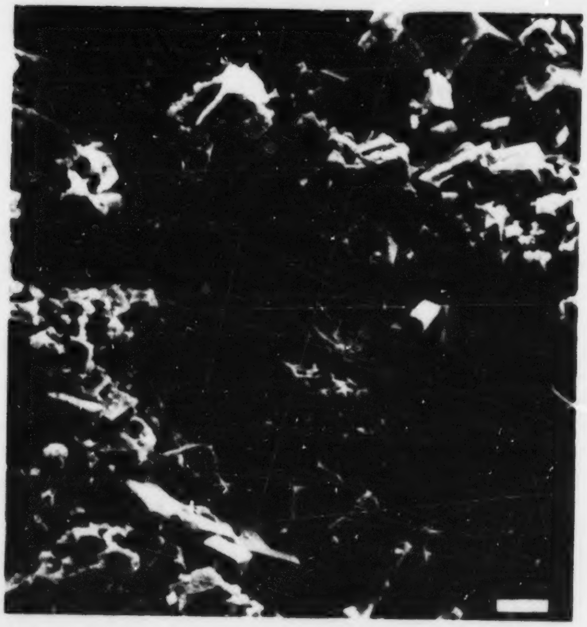

Fig. 17 - Scanning electron micrograph of specimen BF31, 1341.0 m (15-19-6-8W2). Intensely dolomitized lime mudstone with rare micrite grain. Scale bar is 20 μm.

calcareous, since the percolating brines would be depleted of magnesum within a short distance of the brine/sediment interface. Moreover, porosity and permeability at the brine/sediment interface would be rapidly reduced as the carbonate sediment attained maximum dolomitization (Wardlaw, 1979), severely restricting the volume of magnesium rich brine that could percolate through the underlying sediment. This mechanism might explain reservoir rocks such as those at Glen Ewen, Lake Alma and Flat Lake, since many of the MICP curves show a high calcareous content.

In contrast, the middle zone at Benson (Kent *et al.*, 1982) and the reservoir at Oungre display MICP curves and SEM characteristics that suggest dolomitization that reached the inhibition crystal growth stage, followed by dissolution of remnant calcium carbonate, yielding either intercrystal or mixed porosity with micro-cavities. This type of dolomite would most likely form if the magnesium-bearing fluids had a long residence time in the rocks, such as would be expected in some form of mixing zone. The mixing zone process could account for the widespread distribution of the middle zone at Benson. It would also account for a source of fresh water that could dissolve the remnant calcium carbonate, producing the requisite micro-cavities to form a high quality dolomite reservoir rock. The mixing zone may not have been formed during early burial, rather it is quite likely that it was created through a regional groundwater system once the basin margin was uplifted and truncated by erosion. This would place the time of dolomitization at a fairly late stage of diagenesis. Kaldi (1981) identified some late dolomite cements in the Midale Beds of the Midale Field and the senior author has identified scattered late stage dolomite spar and baroque dolomite in thin sections from the Glen Ewen Field. These observations also suggest late stage dolomitization.

SUMMARY AND CONCLUSIONS

Reservoir porosity in two Midale Beds and three Ratcliffe Beds oilfields can be placed into the categories of intercrystal or mixed intercrystal and micro-cavity porosities. They are recognizable from the form of the mercury injection capillary pressure curves. Moreover, the curves indicate variable compositions of reservoir rocks in these fields. This interpretation is based on the observation by Leibel (1982) that entry pressures in the rocks are strongly influenced by the proportion of calcareous material (calcareousness) in the rock.

In two of the fields, Benson and Oungre, the main reservoirs are composed of dolomite with good intercrystal to microcavity porosity, and they show good to excellent reservoir parameters. In constrast, Glen Ewen, Lake Alma and Flat Lake have much poorer reservoir characteristics, in that the rocks consist of a mixture of dolomite and calcium carbonate components.

The poorer quality reservoirs may be due to reflux processes of dolomitization in which magnesium rich brines from overlying evaporite ponds percolated into the subjacent carbonate sediments. Under these conditions, the degree of dolomitization probably would decrease markedly with vertical distance from the original sediment/water interface. In contrast, the main reservoirs at Benson and Oungre may have resulted from a mixing zone mechanism by which a larger area extent of rock could have come into contact with dolomitizing fluids for more prolonged periods. The mixing zone process also would account for the fresh water required to remove residual calcium carbonate to create the high porosities observed in the reservoirs.

ACKNOWLEDGEMENTS

Investigations into the nature of the pore systems of Mississippian hydrocarbon reservoirs has been generously supported by grants from Saskatchewan Energy and Mines; these are much appreciated. Most of the scanning electron micrographs for this paper were made by Dr. J. Dudley of Texaco Canada Limited, Calgary, through a Texaco Research grant to J. B. Burton. In addition, the drafting assistance of P. Kent is gratefuly acknowledged.

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ELECTRIC LOG-CORE RELATIONS IN THE MISSION CANYON FORMATION, NORTH-CENTRAL BURKE COUNTY, NORTH DAKOTA

RODNEY S. STOA, GARY L. STEFANOVSKY, AND DIRK A. SCHWARTZ
North Dakota Geological Survey
Grand Forks, North Dakota

INTRODUCTION

North-central Burke County, North Dakota is experiencing an increase in drilling activity due to new production being established in the upper Frobisher-Alida interval of the Mississippian Mission Canyon Formation. The discovery of hydrocarbons with the upper Frobisher-Alida in the Flaxton Field has caused the petroleum industry to re-evaluate the Burke County area where previous drilling had only penetrated the Midale and Rival subintervals of the Mississippian Charles Formation.

The study are approximately 287,500 hectares (710,000 acres) in north-central Burke County, North Dakota (Fig. 1). There are presently approximately 17 fields producing in this area from the upper Mission Canyon Formation of Mississippian (Osagian) age. Production to date is approximately 2,000,000 bbls.

The focus of this report is to discuss the lithology and corresponding well log characteristics of the upper two units of the Mission Canyon Formation: The Bluell and Sherwood zones. It shall be shown that the use of down-hole logs and coring through the prospective zones are almost essential procedures that should be carried out on all tests in this area.

The Mission Canyon Formaton in this area rests conformably on the Lodgepole Formation and underlies the lowest Mississippian evaporite (Anderson, 1958). In the study area the upper Mission Canyon is charactertized by six mappable sedimentary units which have been informally named for fields or areas which produce hydrocarbons. These units, in descending order, are the Bluell, Sherwood, Mohall, Glenburn, Wayne, and Landa beds (Harris, Land, and McKeever, 1966). This study will deal with only the two upper units, the Bluell and Sherwood beds (Table 1).

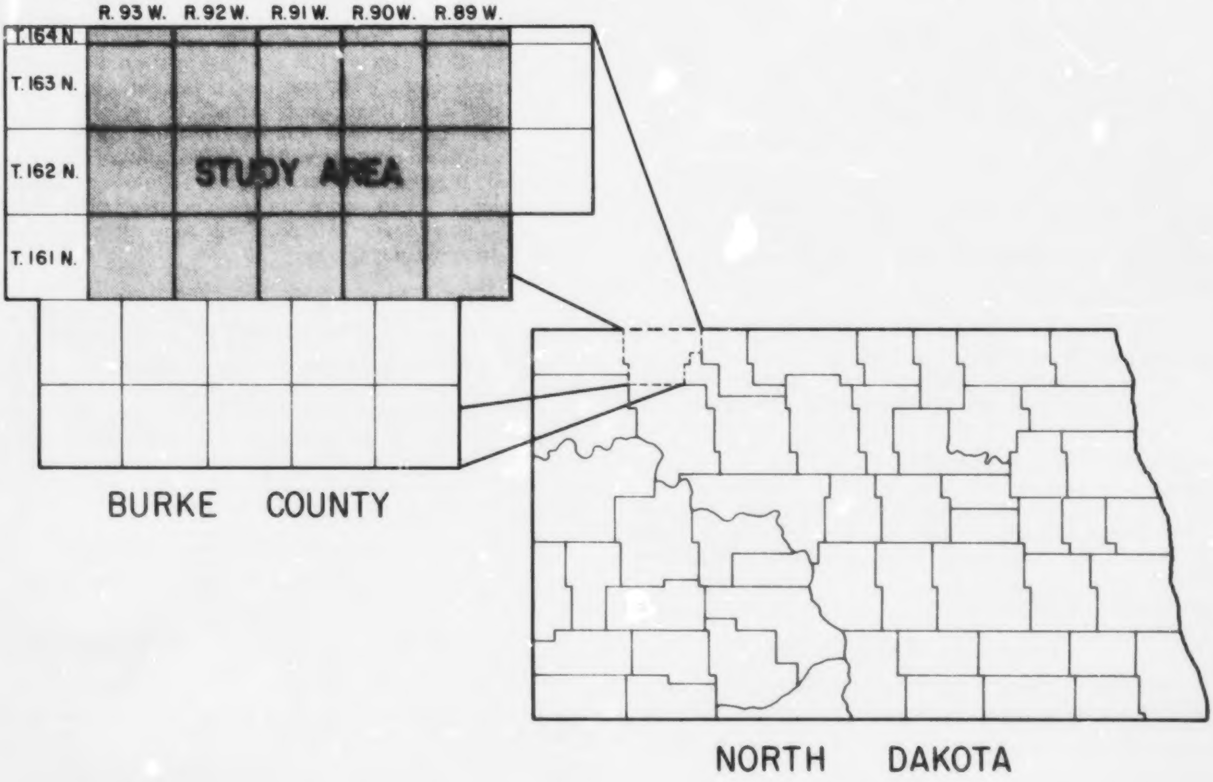
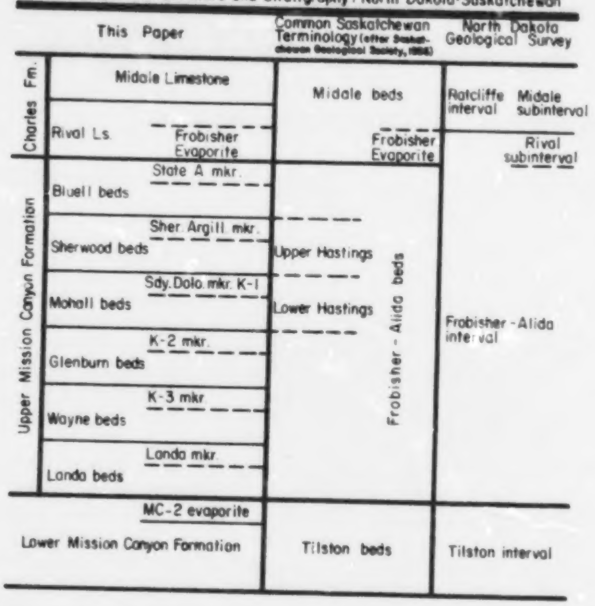


Fig. 1 - Location map.

Mission Canyon Nomenclature and Stratigraphy: North Dakota-Saskatchewan



This Paper			Common Saskatchewan Terminology (after Saskatchewan Geological Society, 1956)		North Dakota Geological Survey	
Charles Fm.	Midale Limestone		Midale beds		Ratcliffe interval	Midale subinterval
	Rival Ls.	Frobisher Evaporite	Frobisher Evaporite			Rival subinterval
Upper Mission Canyon Formation		State A mkr.		Frobisher - Alida beds	Frobisher - Alida interval	
	Bluell beds					
		Sher. Argill. mkr.				
	Sherwood beds		Upper Hastings			
		Sdy. Dolo. mkr. K-1				
	Mohall beds		Lower Hastings			
		K-2 mkr.				
	Glenburn beds					
		K-3 mkr.				
	Wayne beds					
		Landa mkr.				
	Landa beds					
		MC-2 evaporite				
Lower Mission Canyon Formation			Tilston beds		Tilston interval	

Modified from Harris et al, 1966

Table 1 - Mission Canyon nomenclature and stratigraphy: North Dakota and Saskatchewan.

The "State A" marker (Harris *et al.*, 1966) marks the top of the Bluell zone in the study area. There is a sharp contact between this marker and the overlying anhydrite of the Rival subinterval. In the study area, the "State A" (Fig. 2)[1] is a 1.5- to 2.75-metre (5- to 9-foot), tan to light grey, microcrystalline, dolomitic mudstone with microsucrosic porosity.

Below the "State A" lies a 10.7- to 12.8-metre (35-to 42-foot) zone of light brown to greyish brown, micritic, cryptocrystalline limestone containing small amounts of fossil fragments. This limestone is oolitic with anhydrite and calcite pore filling (Fig. 3). This zone is informally referred to as the Bluell beds (Harris *et al.*, 1966).

The Sherwood argillaceous marker, which was only cored in one well in the study area, is about 1.8 metres (6 feet) in thickness, and is comprised of grey to grey brown, micritic, cryptocrystalline, argillaceous limestone with no visible porosity (Fig. 4).

The Sherwood beds are approximately 23.2 metres (76 feet) thick in this area and are medium brown to greyish brown, micritic limestone with intergranular and fracture porosity as well as occasional moldic and vuggy porosity (Fig. 5).These carbonate beds are commonly oolitic and pisolitic, containing fossils and fossil fragments of corals, brachiopods and gastropods (Fig. 6).

LOG-CORE RELATIONS

The zones and markers previously discussed are characterized by easily recognizable down-hole log responses. The most useful devices for distinguishing these zones are the gamma-ray tool and a resistivity device, used in combination. Determination of porosity from logs is possible; however, having a core from the prospective zone along with the down-hole logs will enable more accurate positioning of perforations.

The "State A" marker is characterized on the gamma-ray log by a moderate increase in radioactivity while the resistivity of this marker will show a corresponding decrease (Fig. 7). The Bluell beds begin under the "State A" and are illustrated by a decrease in radioactivity and a corresponding increase in resistivity suggesting a cleaner, less shaly section as is shown in Figure 7. The Sherwood argillaceous marker is identified by a radioactivity increase along with an increase in resistivity (Fig. 7). The Sherwood beds are shown to have a radioactivity decrease and an increase in resistivity.

The value of using electric logs cannot be overstated. The most useful tools to use in the area appear to be the gamma-ray, resistivity, and porosity logs. The drilling time log is also a useful tool in this area as any drilling breaks are easily correlated to porosity zones throughout the core.

The most valuable information to be obtained is by coring from just above the "State A" marker through the Bluell and Sherwood beds. In cores fracture zones are readily apparent and, by use of down-hole logs in conjunction with the core, very accurate control can be accomplished in perforating.

COMMON COMPLETION PRACTICE

The most common completion practice in this area is to perforate those zones which, on the log and in the core, appear to be less argillaceous on the gamma-ray, and have slight separation of the RXO, LLS or LLM and LLD on the resistivity log. Productian testing is performed and, if successful, the well is put on production. If this is not successful the perforations are squeezed and the next zone of interest is perforated. This procedure is repeated until the well is producing or all the zones are tested. If repeated perforation tests are unsuccessful the well is plugged. With a core and accompanying well logs the expense of unnecessary perforations and squeezing could very possibly be avoided.

CONCLUSIONS

The Bluell and Sherwood are two potentially productive beds in the upper Mission Canyon. There are two distinct lithologies present and they can both be identified with the use of down-hole logging methods. By coring these zones the value of the logs increases tremendously and better perforation control can be accomplished. Unnecessary perforations and/or possible cement squeezes may also be avoided.

Fig. 2 - Tan to light grey, microcrystalline limestone of the "State A" marker showing microsucrosic porosity.

Fig. 3 - Bluell beds light brown to greyish brown, micritic, cryptocrystalline limestone of the Bluell beds which is occasionally oolitic and has anhydrite and calcite core filling.

Fig. 4 - Grey to grey brown, micritic, cryptocrystalline, argillaceous limestone of the Sherwood argillaceous marker (no visible porostiy).

Fig. 5 - Sherwood beds medium brown to greyish brown, fossiliferous, micritic, oolitic and pisolitic limestone of the Sherwood beds. Porosity is typically intergranular and fracture type although occasionally moldic and vuggy.

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[1] All photos from the Northern Pump Company, Ormiston #3, T162N, R90W, sec. 25 SW/SE, Bowbells Field.

1 inch

1 inch

1 inch

1 inch

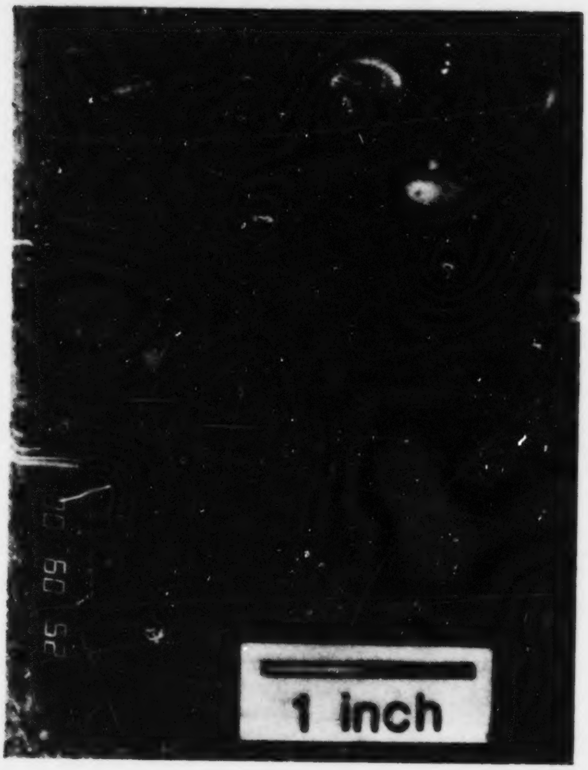

Fig. 6 - Oolitic and pisolitic Sherwood beds containing fossils and fossil fragments.

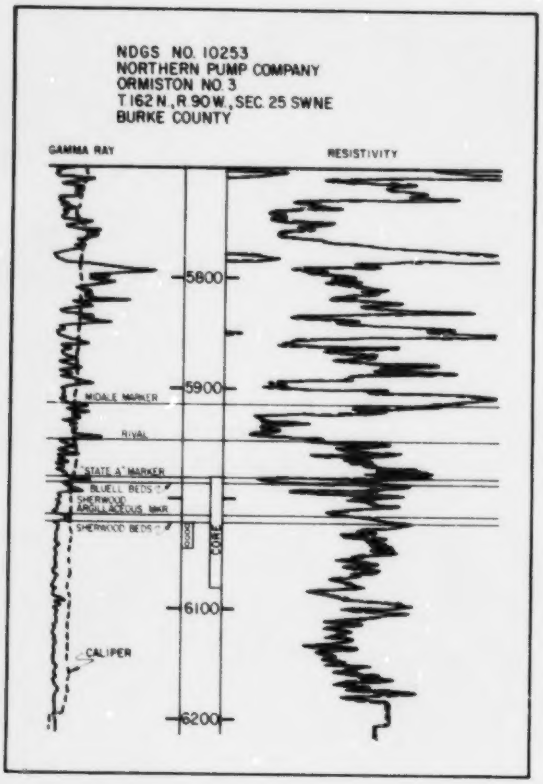

Fig. 7 - Geophysical log profile; Northern Pump Company Ormison No. 3 well.

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Anderson, Sidney B., 1958. North Dakota Geological Survey Report of Investigation 31, pp. 1-9.

Harris, Steven H., Land, Cooper B., Jr., and McKeever, John H., 1966. Relation of Mission Canyon Stratigraphy to Oil Production in North-Central North Dakota: American Association of Petroleum Geologists Bulletin, v. 50, pp. 2269-2276.

DEPOSITIONAL HISTORY OF THE UPPER PORTION OF THE GLENBURN ZONE, GLENBURN FIELD, NORTH DAKOTA

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The Glenburn zone of the Frobisher Alida Interval in the Mississippian Mission Canyon Formation is a well known oil producer in Bottineau and Renville Counties, North Dakota. Approximately 30-50 feet of core from each of 10 wells in the upper Glenburn zone, in the Glenburn Field (Fig. 1) was studied in order to determine the depositional environment. Cored intervals from these wells (Fig. 2), beginning at the limestone-anhydrite contact at the base of the K-2 marker, and a total of 80 thin sections, were described in detail.

In the northern portion of the Glenburn Field, the upper section of the core described contains massively bedded anhydrite which grades into interbedded dolomite and anhydrite. Underlying the dolomitic anhydrite, there are interbedded dolomitic wackestones and packstones containing pore filling anhydrite and minor amounts of pore filling calcite. To the south, cores show a sharp contact between the massively bedded anhydrite and the underlying, interbedded wackestones, packstones and occasional mudstones and grainstones. Only minor amounts of pore filling anhydrite occur near the contact while pore filling calcite is prevalent throughout.

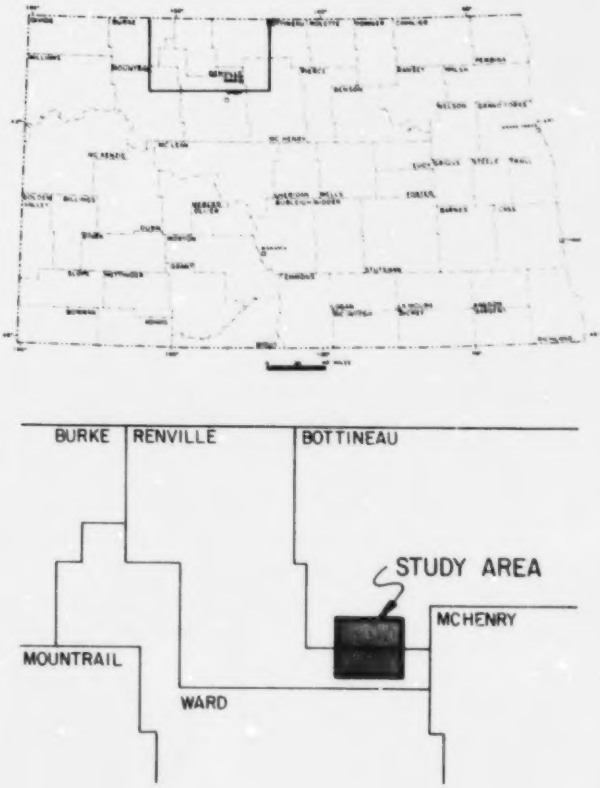


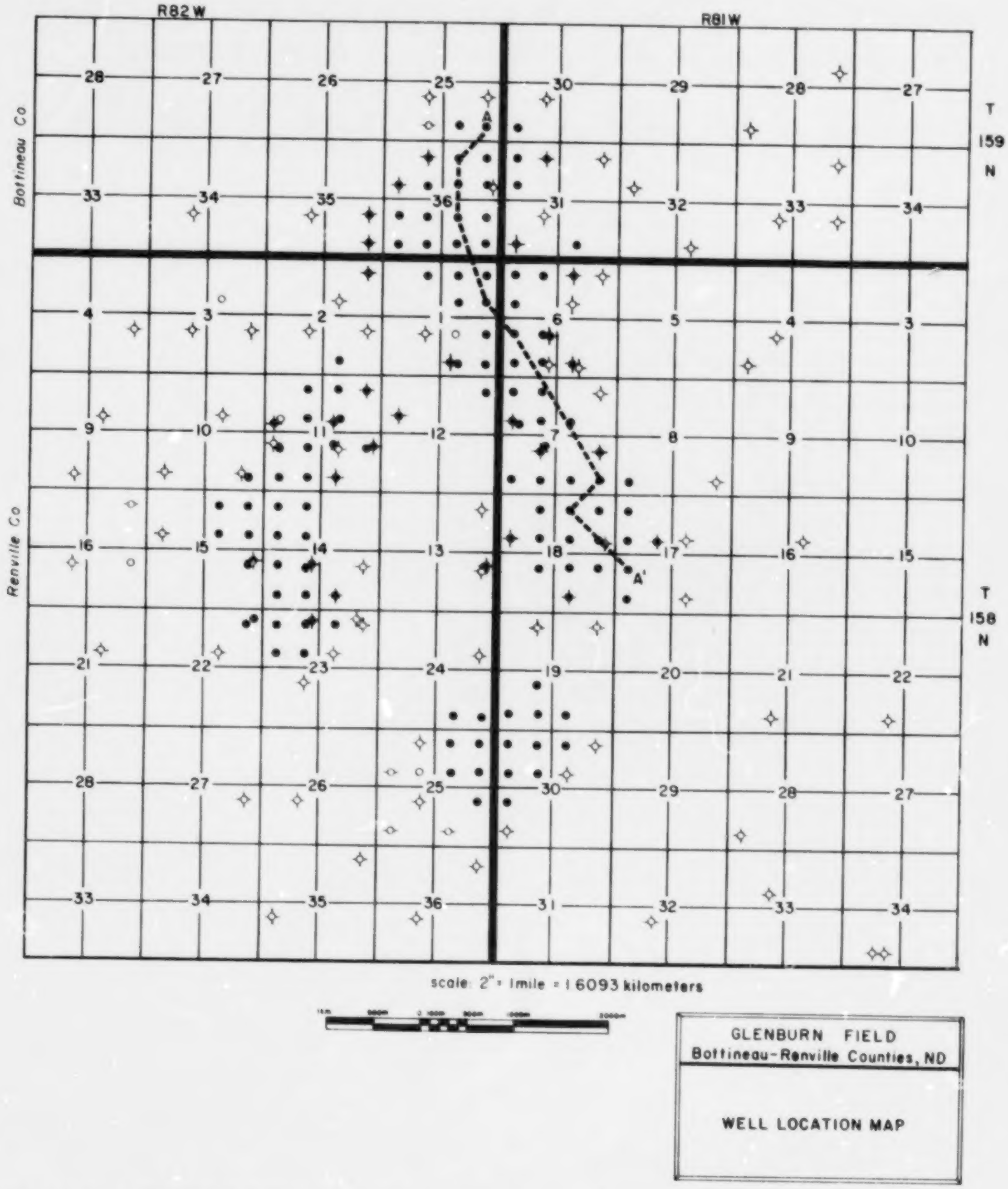
Fig. 1 - Location map of the study area in Bottineau and Renville Counties, North Dakota.

The major allochems present in these lithologies are spherical to subspherical, occasionally broken, coated grains which vary from less than 0.5mm to 5.0mm in diameter, and occur as normal and reverse graded, well-packed grains, as randomly-packed grains, and as grains floating in a mud matrix. Coated grains vary in degree and type of coating with some being well-defined, concentrically laminated grains while other grains have fewer, thicker, less distinct laminations. There is an increase in the abundance and size of well-defined, concentrically laminated grains to the south, while fewer, smaller, less distinct coated grains are more conspicuous in the north. Fossils, mainly ostracods and occasional mollusk fragments are rare, and occur mainly in the lower portions of the southern cores in association with and as the nuclei of the coated grains.

The depositional environment inferred from allochem distributions in cores and thin sections suggests a restricted marine environment, containing small, randomly located shoals (Fig. 3). An increase in the abundance of fossil allochems indicates that more open marine conditions were present to the south. The presence of zones of grainstones and packstones randomly distributed within more mud rich lithologies supports the occurrence of small, localized shoals rather than a large, single barrier.

The numerous small shoals located in what is now the southern portion of the Glenburn Field may explain the increased abundance of coated grains in that direction. The small, randomly located shoals may have acted as baffles, restricting circulation on their leeward side. This allowed the accumulation of carbonate sediment, derived from the nearby shoals, to be deposited in the adjacent topographically low areas. These sediments were preserved as slightly fossiliferous mudstones and coated-grain wackestones and packstones. The occurrence of coated-grain packstones and grainstones suggests the presence of higher-energy conditions on the tops of the shoals. During storms, coated grains were transported from these higher-energy shoal-tops and deposited in the more protected intershoal lows, resulting in relatively mud-rich, normal and reverse graded beds containing occasional broken grains and rare fossil fragments.

The absence of fossils, in addition to the increased abundance and thickness of massively bedded anhydrite, suggests a more restricted hypersaline environment to the north in which subaqueous evaporites were deposited in a lagoonal setting. With time, evaporitic conditions prograded towards the south overstepping previously deposited carbonates.


R82W
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Bottineau Co
Renville Co
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33
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scale: 2" = 1mile = 1.6093 kilometers
GLENBURN FIELD
Bottineau-Renville Counties, ND
WELL LOCATION MAP

Fig. 2 - Well location map, Glenburn Field, Bottineau and Renville Counties, North Dakota.

DIAGRAMMATIC BLOCK MODEL OF UPPER GLENBURN ZONE
ENVIRONMENTS, GLENBURN FIELD, NORTH DAKOTA

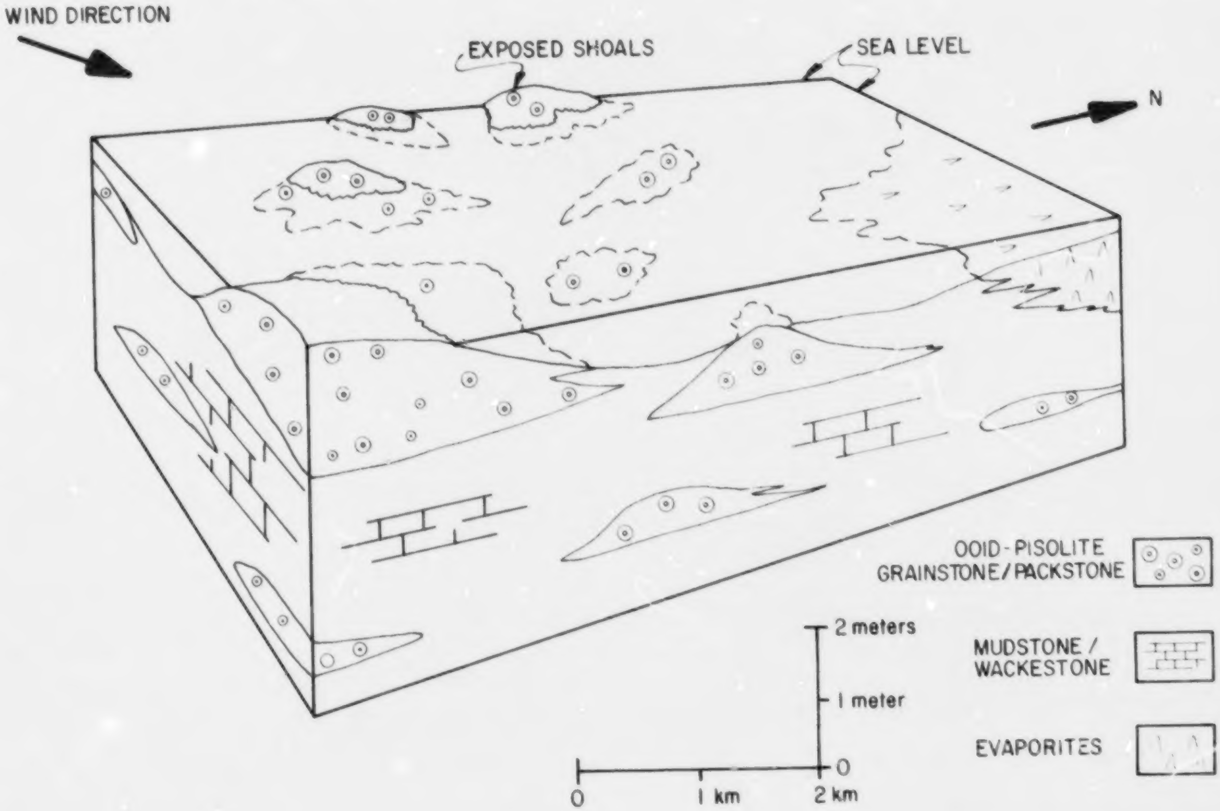
WIND DIRECTION
EXPOSED SHOALS
SEA LEVEL
N
OOID-PISOLITE GRAINSTONE/PACKSTONE
MUDSTONE / WACKESTONE
EVAPORITES
2 meters
1 meter
0
0
1 km
2 km

Fig. 3 - Isolated shoals baffled energy and produced low energy conditions in inter-shoal and back-shoal areas. Subaqueous evaporites formed in lowest energy environments.

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OIL PRODUCTION FROM THE MISSISSIPPIAN FROBISHER BEDS OF THE INNES FIELD, SOUTHEASTERN SASKATCHEWAN: THE INTERACTION OF STRUCTURAL POSITION AND PORE GEOMETRY

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ABSTRACT

Hydrocarbon accumulations may be confined either partially or completely by structural closure, however maximum recovery is not necessarily sited at the apex of the structure. Such is the case for optimum fluid recovery from the Innes Field, a multi-level producer in the Mississippian Frobisher Beds. A single pool, IFBP-2, was selected for study, including depositional and diagenetic histories and a pore geometry model. The most productive wells perforated within this pool, which is a structural-stratigraphic trap, are located down-dip from the culmination of the structure. This area is also the site of tepee structure formation and lithologies dominated by mega-pores (formed by eogenetic erosion of uncemented matrix), suggesting there were depositional and diagenetic controls that in turn influenced oil production. Contour maps of parameters obtained for the pore geometry model show that the optimum petro-physical parameters occupy the same location, so, however depositional and diagenetic processes influenced the pore geometry, the overall effect was beneficial to potential oil recovery.

Statistical comparison of mercury-injection capillary-pressure curves distinguishes divisions of highly permeable and less permeable lithologies, which have distinctive spatial distributions. The area of highly permeable lithologies incorporates the optimum production area. Visual comparison identifies groups of curves with similar pore systems, the most common curves in the highly permeable, optimum production area have undergone recrystallization to coarse miscrospar, a result of fresh water flushing, hence the association of shallow water structures and sediments, and turbulent water eogenetic processes. Recrystallization occludes very fine pore throats increasing the uniformity of the pore throat size distribution and improving the enhanced recovery potential.

The location of the shallow water area is determined by a positive feature on the underlying substrate.

INTRODUCTION

Optimum oil production from a structural trap is generally, but not always, recorded from those wells located on the crest of the structure. In the case of the Mississippian Innes Field, oil production is determined not only by structural position but also by pore geometry.

GEOGRAPHICAL LOCATION

The Innes Field is located in southeastern Saskatchewan (Fig. 1), approximately 30 km east of Weyburn (Fig. 2), in the northwest-southeast belt of Mississippian carbonate oilfields.

GEOLOGICAL SETTING

The reservoir rocks of the Innes Field are the Frobisher Beds, part of the Mississippian Madison Group of the northeast Williston Basin.

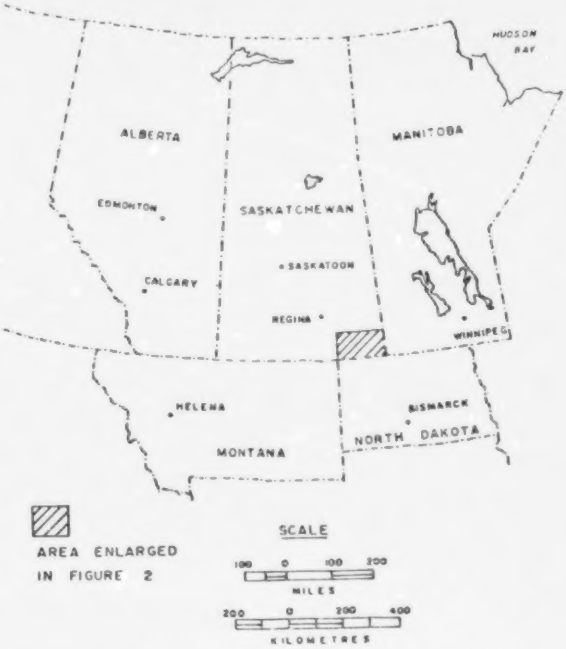

Fig. 1 - Location map (from Crabtree, 1982).

The Frobisher Beds form the uppermost portion of the Frobisher-Alida Beds (Fig. 3; Fuzesy, 1966). Within the study area, the Frobisher Beds are thick, coated grain, cyclically deposited, shallow-water carbonates. Crabtree (1982) has suggested that these rocks are derived from subtidal to intertidal bank sediments dissected by tidal drainage channels, and that they resemble the deposits of the Quarternary wedge-shaped bank in Shark Bay, Western Australia (Davis, 1970).

Repeated minor marine transgressions in an overall regressive setting resulted in the cyclical deposition of either coated grain packstones or skeletal packstones. Four cycles culminate in argillaceous dolomites or in argillaceous zones which act as reservoir seals dividing the reservoir into four separate pools. These low permeability horizons are probably overbank deposits from tidal drainage channels (Crabtree, 1982).

METHODS OF STUDY

A single pool, Innes Frobisher Beds Pool-Two (IFBP-2), was selected for detailed investigation which included reviewing depositional and diagenetic histories of the reservoir rocks and, in particular, analysis of their pore geometry. This

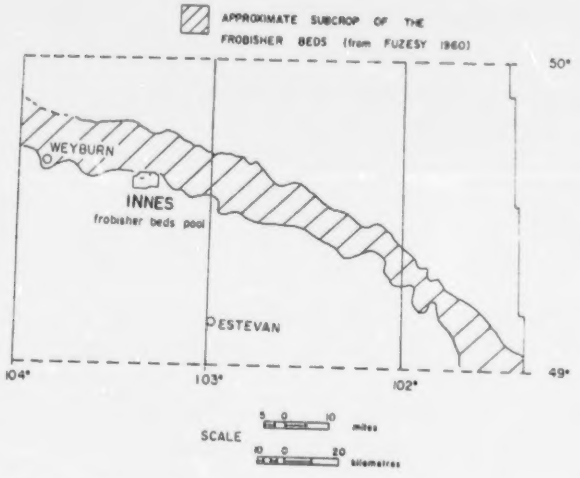
APPROXIMATE SUBCROP OF THE FROBISHER BEDS (from FUZESY 1960)
WEYBURN
INNES
frobisher beds pool
ESTEVAN
50°
49°
104°
103°
102°
SCALE
5 0 10 miles
10 0 20 kilometres

Fig. 2 - Location map of the study area.

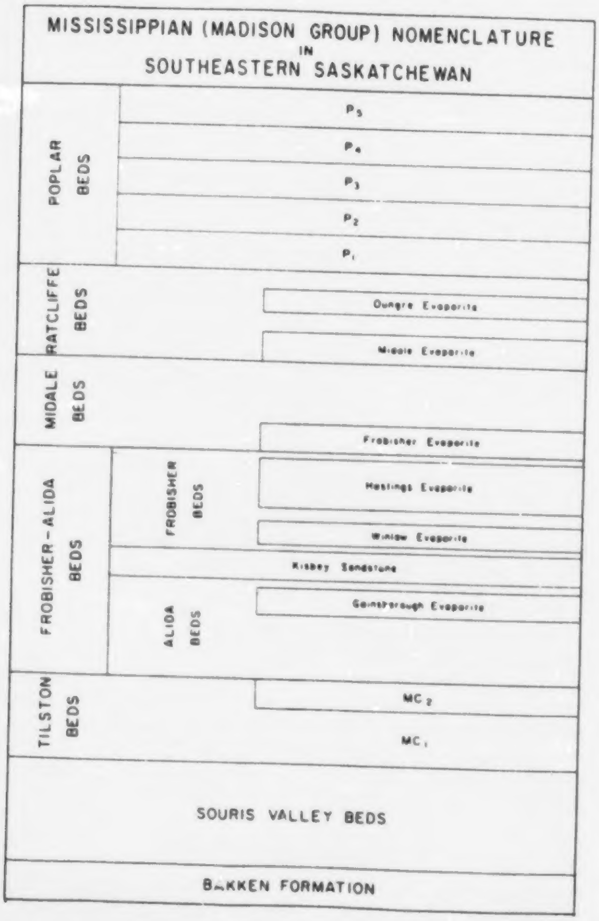
MISSISSIPPIAN (MADISON GROUP) NOMENCLATURE IN SOUTHEASTERN SASKATCHEWAN
POPLAR BEDS
P5
P4
P3
P2
P1
RATCLIFFE BEDS
Oungre Evaporite
Midale Evaporite
MIDALE BEDS
Frobisher Evaporite
FROBISHER-ALIDA BEDS
FROBISHER BEDS
Hastings Evaporite
Winlaw Evaporite
Kisbey Sandstone
ALIDA BEDS
Gainsborough Evaporite
TILSTON BEDS
MC2
MC1
SOURIS VALLEY BEDS
BAKKEN FORMATION

Fig. 3 - Mississippian (Madison Group) nomenclature in southeastern Saskatchewan (from Fuzesy, 1966).

analysis was based on permeability and porosity determinations, thin section studies and mercury injection capillary pressure (MICP) measurements following the techniques described by Purcell (1949); Burdine *et al.* (1950); Wardlaw (1976) and Wardlaw and Taylor (1976). In addition, various useful parameters were derived from the resulting graphical plots of MICP analyses (Fig. 4).

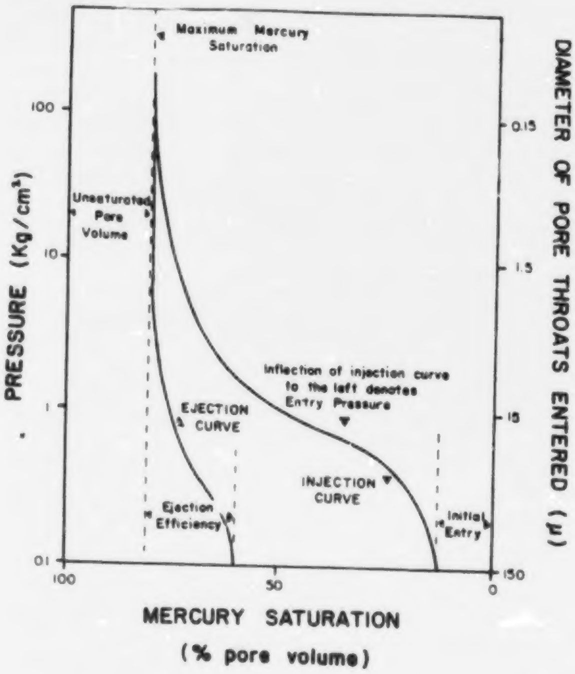

Fig. 4 - Petrophysical parameters determined from mercury capillary injection and ejection curves.

HYDROCARBON PRODUCTION

Oil production from IFBP-2 began in 1965 and continues to the present time, mostly under primary water drive although 70 percent of the estimated reserves available using this recovery method have been depleted. The average annual oil production from the wells perforated within IFBP-2 range from 5000 barrels per year to 700 barrels per year. Oil from IFBP-2 accumulated in a structural-stratigraphic trap in which the dominant control influencing hydrocarbon concentration is a domal structure (Fig. 5). A second controlling influence is the decreasing permeability towards the northern edge of IFBP-2 caused by a facies change from the coated grain reservoir rock to channel levee type deposits (Crabtree, 1982). The southern limit of the pool is determined by the theoretical oil/water interface which is at an elevation of 726 m below sea level.

A map of IFBP-2's fluid production (Fig. 6) compiled from average annual oil production and current water/oil ratios shows that the crest of the dome does not yield the greatest volume of oil. The most prolific area, in terms of hydrocarbon recovery is situated on the down-dip flank of the dome. Decreasing oil recovery and increasing water production take place towards the channel levee sediments in the north. Similar fluid recovery changes occur towards the south. In fact, water

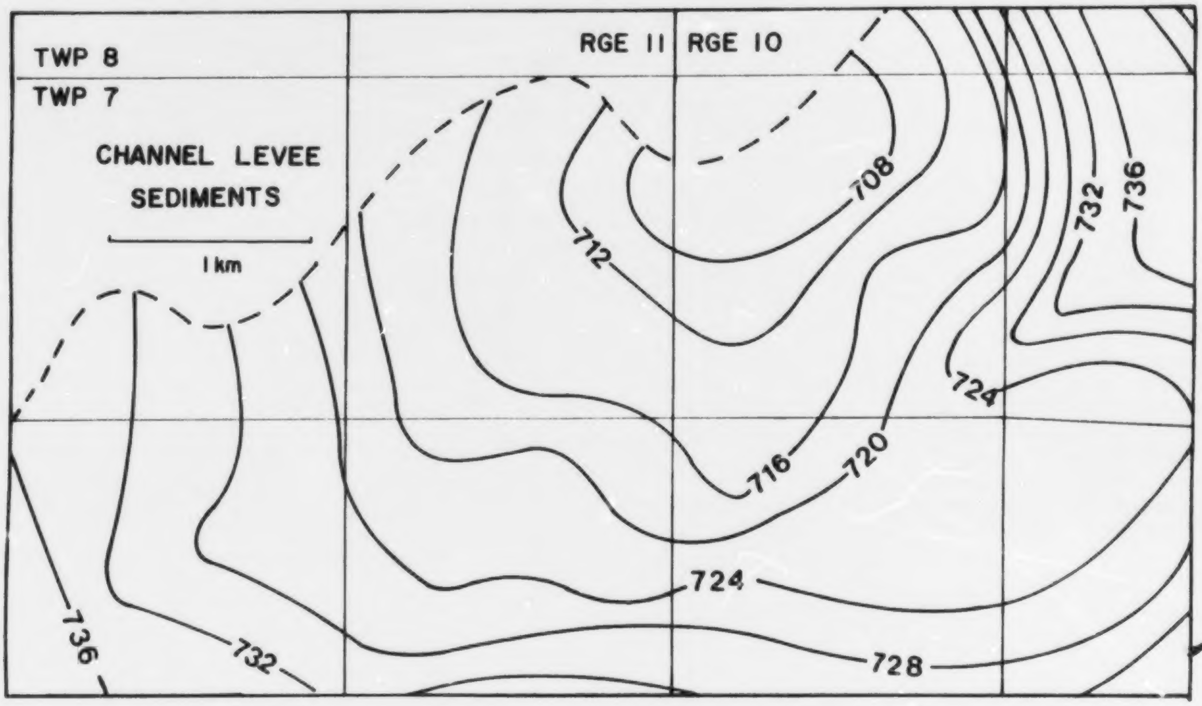
TWP 8
TWP 7
RGE 11
RGE 10
CHANNEL LEVEE SEDIMENTS
1 km
708
712
716
720
724
724
728
732
732
736
736

Fig. 5 - Structural contour map of IFBP-2. Contour values in metres below sea level (from Crabtree, 1982).

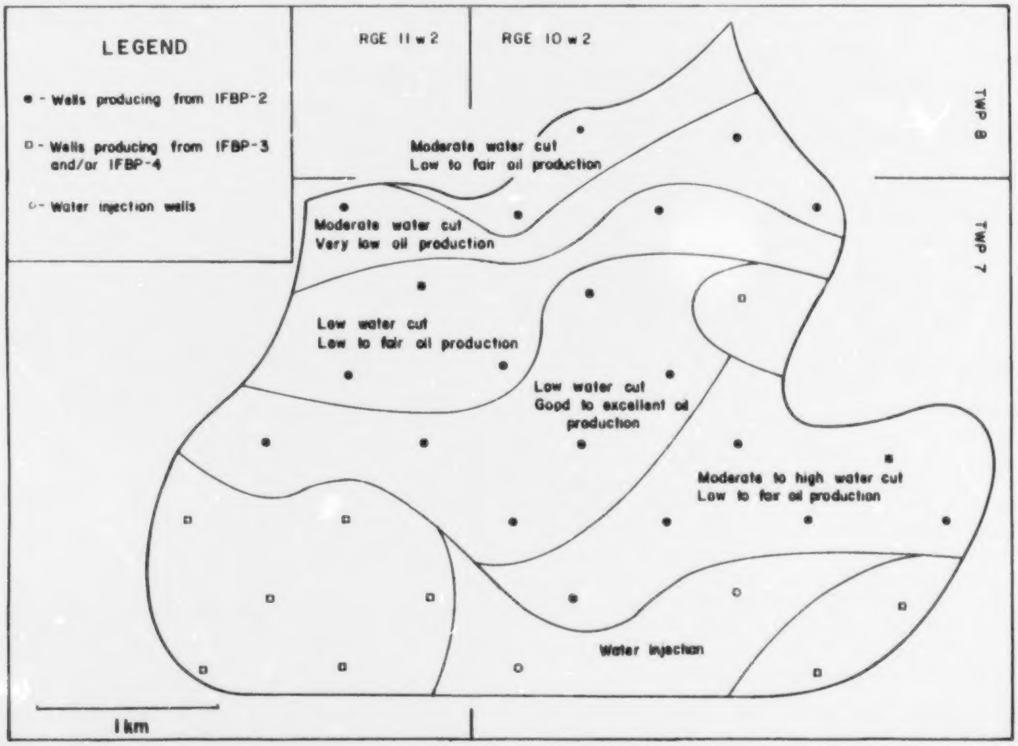
LEGEND
● - Wells producing from IFBP-2
□ - Wells producing from IFBP-3 and/or IFBP-4
○ - Water injection wells
RGE 11 w 2
RGE 10 w 2
TWP 8
TWP 7
Moderate water cut
Low to fair oil production
Moderate water cut
Very low oil production
Low water cut
Low to fair oil production
Low water cut
Good to excellent oil production
Moderate to high water cut
Low to fair oil production
Water injection
1 km

Fig. 6 - Areas of oil production.

breakthrough began a few years after production start-up in the pool's most southerly wells, which have been used for water injection since 1970 and 1971.

RELATIONSHIP OF DEPOSITIONAL ENVIRONMENT, DIAGENSIS AND HYDROCARBON PRODUCTION

Comparison of data obtained from the fluid production map, from interpretations of the area's depositional and diagenetic histories and from pore geometry analysis permits recognition of the main factors controlling hydrocarbon recovery in IFBP-2.

Tepee structures, and sediments associated with tepee structures, occur in the upper cyclical deposits of the Frobisher Beds of the Innes Field. They fall within an approximately one kilometre wide zone that is subparallel to (but not immediately adjacent to) the channel levee (Fig. 7). The zone of tepee formation coincides with the area of optimum oil production, suggesting that lateral variations in the depositional environment may have influenced the potential oil recovery.

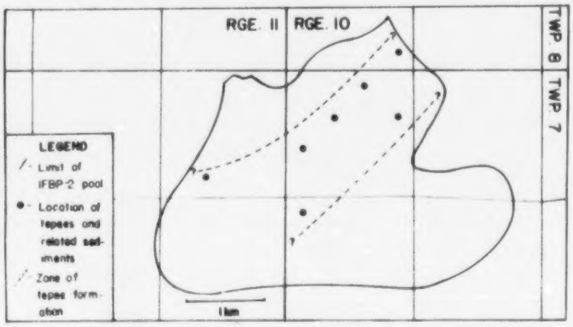
RGE. 11
RGE. 10
TWP. 8
TWP. 7
LEGEND
/ - Limit of IFBP-2 pool
● - Location of tepees and related sediments
/ - Zone of tepee formation
1 km
?

Fig. 7 - Location of tepee structures and related sediments within the Frobisher Beds.

Choquette and Pray (1970) note that porosity in carbonates is bi-modal, composed of interparticle mega- and meso-pores and intramatrix meso- and micro-pores. They also point out that the largest equidimensional mega-pores or vugs appear to form by eogenetic erosion of uncemented matrix following differntial matrix cementation. During mercury injection capillary pressure analysis, these large pores become saturated with mercury without the application of pressure to the injection system and are represented on the capillary pressure plots by the Initial Entry (Fig. 4). As increasing pressure is applied to the system, intramatrix porosity is eventually invaded by mercury - a process shown in Figure 4 by the inflection of the injection curve to the left. The presence of large pores increases the accessibility of fine intramatrix porosity to fluids which enter intramatrix pores via the interparticle porosity. This accessibility improves as the number of large pores become greater and intramatrix porosity is no longer shielded by fine pore throats and tortuous flow paths. The overall effect is to displace the inflection on the injection curve downwards relative to the pressure axis (Akhurst, 1981).

Some Innes Field rock types have pore systems so dominated by mega-pores that their injection curves lack an initial vertical component (Fig. 8); extrapolated entry pressure for the intramatrix pores are less than the minimum pressure attainable. Lithologies with this form of injection curve mainly fall in a northeast-southwest trending band (Fig. 9) which is coincident with the area of optimum oil production. Upper and lower samples were cut from IFBP-2 at most well locations. At the northeasterly end of the band shown in Figure 9, both samples characteristically have injection curves with entry pressure less than the minimum pressure attainable.

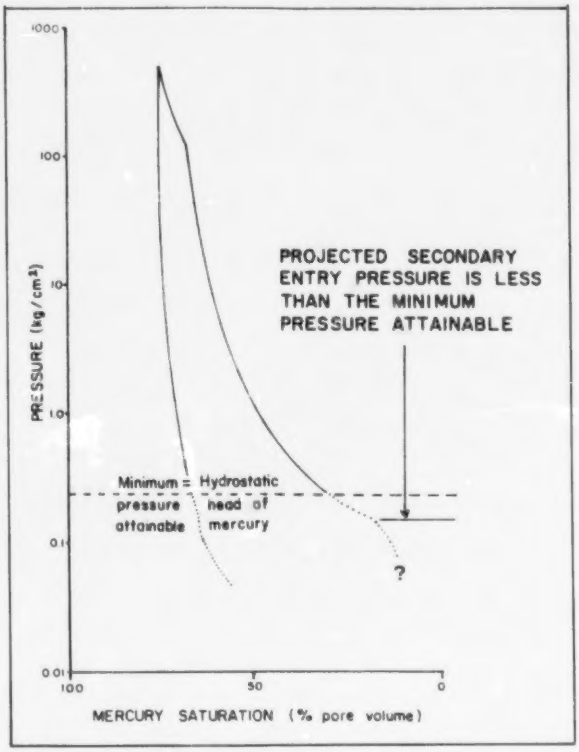

Fig. 8 - Capillary injection curve characterized by a secondary entry pressure less than the minimum pressure attainable.

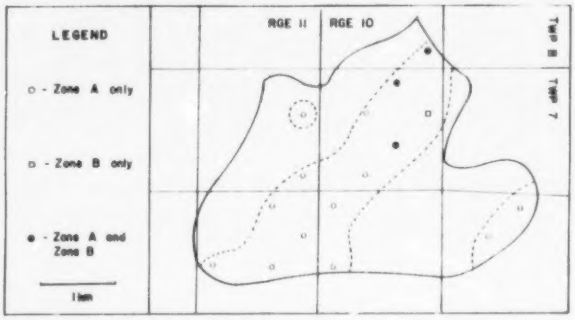

Fig. 9 - Location of samples characterized by secondary entry pressures less than the minimum pressures attainable.

The petrophyscial parameters from the pore geometry model were also used to compile contour maps. The area of optimum production was generally found to be concordant with the contours of maximum porosity on the porosity map (Fig. 10) and contained the highest range (14-22 percent) of porosity values recorded from the Innes Field. Contours are aligned roughly parallel to the outline of the area of optimum production. Coincidence of the optimum production area with the areas of a) tepee formation (Fig. 7) and b) lithologies dominated by mega-porosity (Fig. 8) suggests that the development of the pore geometry was influenced by both depositional and eogenetic processes.

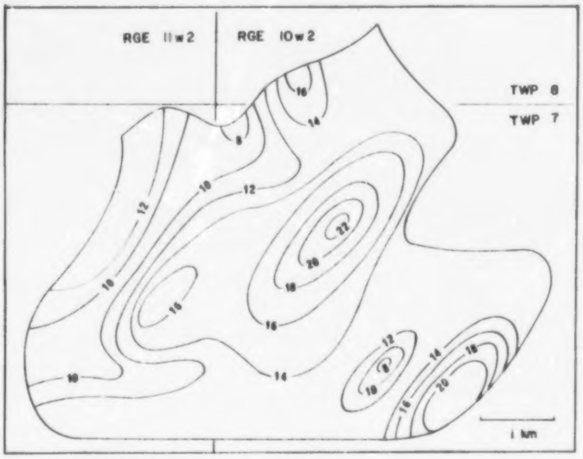

Fig. 10 - Porosity map of IFBP-2. Contour values in percentage porosity.

Sediments in the Frobisher Beds associated with tepee structures include thin horizons of vadose pisoids (Dunham, 1969), which were probably deposited in extremely shallow waters and were intermittently exposed. In a study of tepees from the Permian Reef Complex of Texas, Esteban and Pray (1977) observed that the structures formed where the water was shallowest and most turbulent. This depositional environment appears to apply to the Frobisher Beds. Because the mega-porosity in these beds formed by eogenetic erosion of uncemented matrix, the shallow turbulent conditions conducive to tepee formation also promoted the generation of mega-pores.

PORE GEOMETRY MODEL

Fifty-six plug samples were cut from 34 well locations in IFBP-2 for construction of a pore geometry model of the pool. Six parameters, chosen because they appeared to have the greatest influence on reservoir quality (Eriyagama, 1983 and Kent, unpublished), were used to describe the pore geometry of these samples: porosity and permeability were measured directly from each sample whereas ejection efficiency, unsaturated pore volume, entry pressure and curve slope were obtained from the corresponding mercury injection and ejection curves (Fig. 4). Multivariate discriminant analysis using the Cosine θ Measure of Similarity (Imbrie and Purdy, 1963) premitted the convenient comparison of results and the selection of samples with similar properties. Entry pressure was found to be least significant in this miltivariate analysis as its omission from the analysis did not greatly affect the derived similarity coefficients.

The reason for the low significance of entry pressure in this analysis is not clear, but may be related to the large size of the pores. Entry pressures were too low to be attained in the equipment used and were therefore calculated from measured pore diameters. Consequently, the entry pressures are inapplicable because they are based on the measurement of pore, not porethroat, diameters, or the mega-pores do not contribute to ejection efficiency perhaps due to a large pore-to-throat size ratio (Wardlaw and Cassan, 1978).

Five divisions of samples were distinguished by Cosine θ analysis and are shown in Table 1. When samples in these divisions are plotted onto a location map, they show a distinctive distribution pattern (Fig. 11). Samples in Divisions II and III tend to group together as do samples in Division IV and V. Transition zones which contain samples from all divisions except Division V separate areas with dominant Division II and III samples from those with Division IV and V samples. Table 1 reveals permeability to be the main property that distinguishes between the two groups which are described accordingly (High Permeability, Low Permeability). If the transition zones with permeable Division I samples are combined with the area containing Division II and III samples, a northeast-southwest band of highly permeable rocks is delineated, centred over the area of maximum oil production. Elsewhere the lithologies are much less permeable (Divisions IV and V).

The samples were categorized not only statistically but also by a visual comparison of the shapes of the injection and ejection curves of each specimen analyzed. Six curve arrays containing samples with similar pore systems were recognized (Fig. 12). However, not all samples within a given curve array had the same diagenetic history.

Almost half the curves of samples from the high permeability area of Figure 11 are included within a single curve array characterized by a) an absence of very fine porosity giving an asymptotic approach to the maximum mercury saturation value, b) a shallowly inclined plateau of mercury invasion indicating a very uniform pore throat size distribution and c)

TABLE 1 — AVERAGE PARAMETER VALUES IN PORE SYSTEM DIVISION 2, IFBP-2

	HIGH PERMEABILITY			LOW PERMEABILITY	
	Div. I	**Div. II**	**Div. III**	**Div. IV**	**Div. V**
Porosity (%)	15.2	16.4	15.7	12.3	10.5
Entry Pressure (kg/cm^2)	0.006	0.007	0.007	0.005	0.005
Curve slope (°)	25	20.3	23.5	37	12.2
Ejection Efficiency (%)	20	23	16.5	10.5	38
Unsaturated Pore Vol. (%)	20	19	14.8	32	18
Permeability (md)	56	470	27	2.5	4.5
No. of Samples	11	17	9	16	3

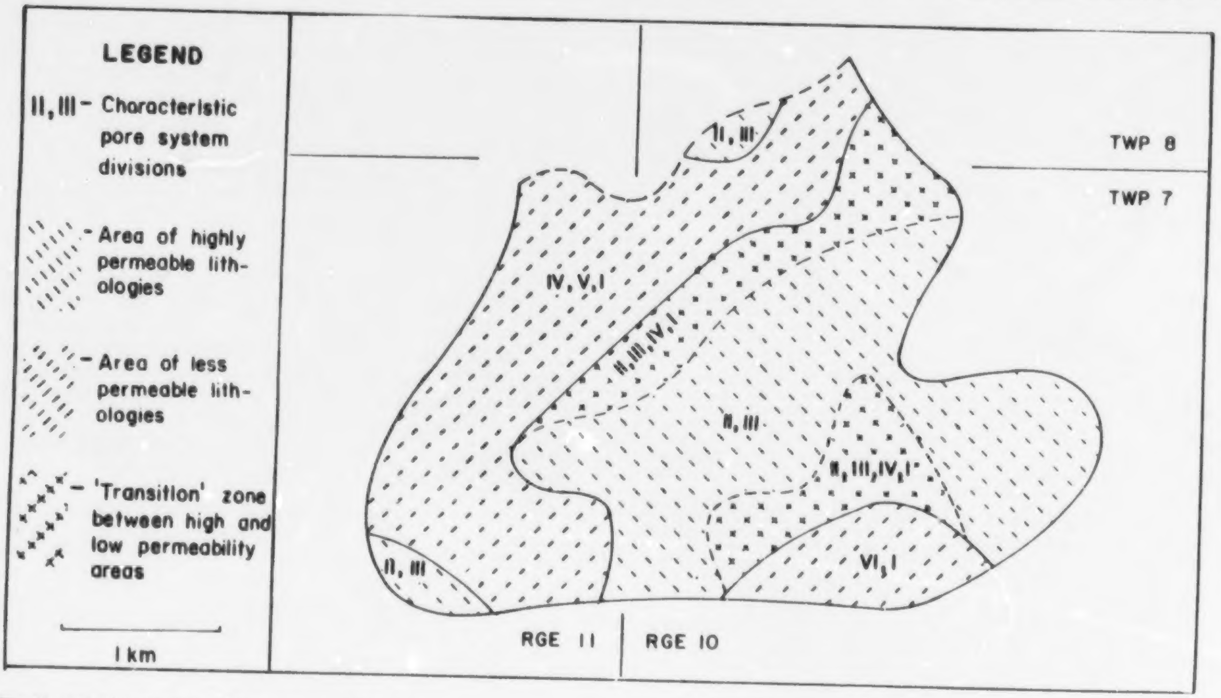
LEGEND
II, III - Characteristic pore system divisions
- Area of highly permeable lithologies
- Area of less permeable lithologies
- 'Transition' zone between high and low permeability areas
1 km
TWP 8
TWP 7
RGE 11
RGE 10
II, III
IV, V, I
II, III, IV, I
II, III
II, III, IV, I
VI, I
II, III

Fig. 11 - Spatial distribution of the pore system divisions.

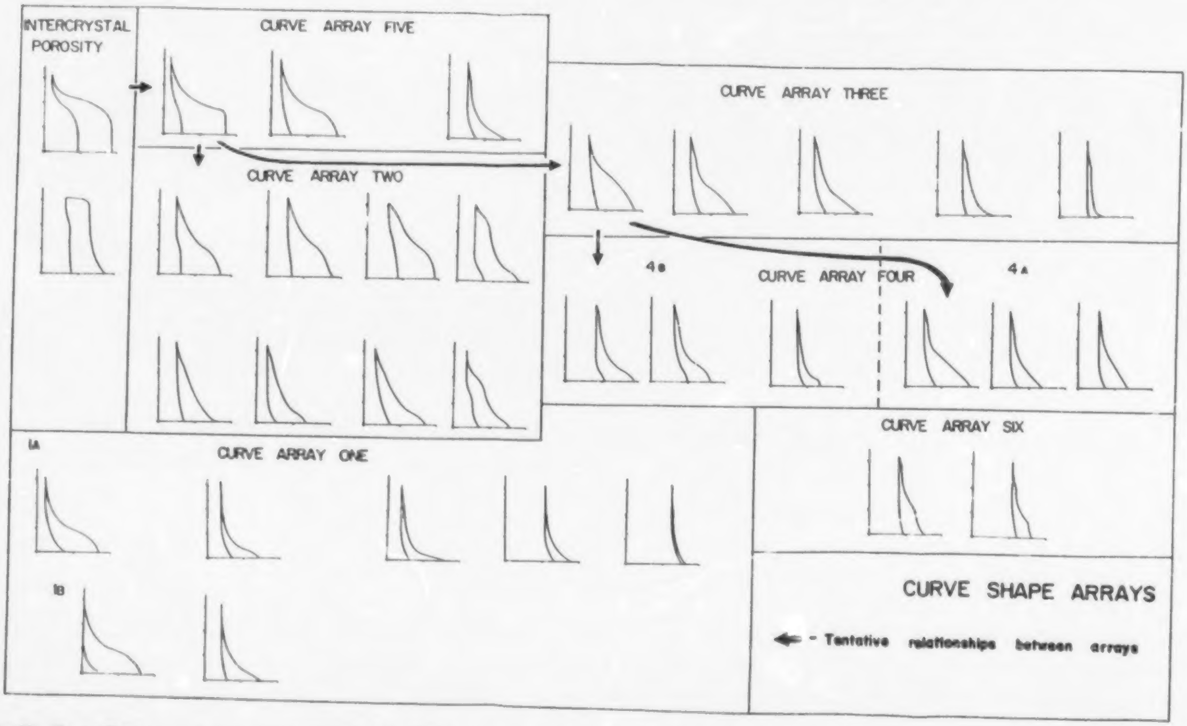
INTERCRYSTAL POROSITY
CURVE ARRAY FIVE
CURVE ARRAY THREE
CURVE ARRAY TWO
4B
CURVE ARRAY FOUR
4A
IA
CURVE ARRAY ONE
CURVE ARRAY SIX
IB
CURVE SHAPE ARRAYS
- Tentative relationships between arrays

Fig. 12 - Six capillary pressure curve arrays recognized in IFBP-2 samples by visual comparison of curve shapes.

similarly shaped injection and ejection curves (Fig. 13). Thin sections of samples from this curve group are dissimilar in terms of lithology and porosity type, but all show signs of recrystallization to coarse microspar. Neomorphism of matrix and grains is not restricted to this curve assemblage, but the crystals in this assemblage are unusually large, 20µm and 30µm in diameter. Folk (1974) points out that aggradation of micrite to microspar is related to the flushing out of inhibiting Mg^{2+} ions released during the inversion of argagonite to calcite. Thus the micro-pores within the matrix become occluded by the developing calcite crystals. Microspar growth to such a large size as described here has occluded all pores less than 1.5µm in diameter to give the characteristic curve shape.

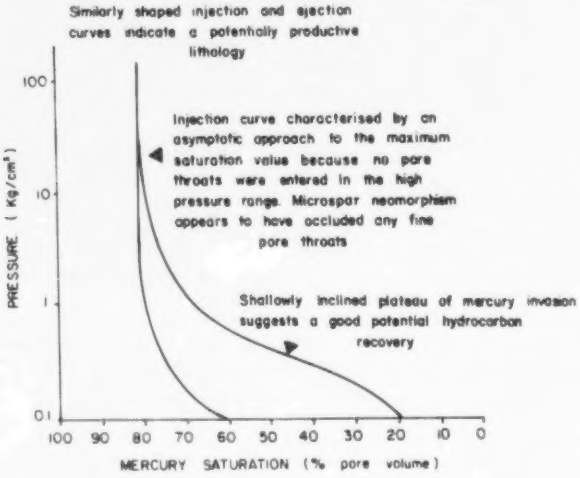

Fig. 13 - Capillary pressure curves from permeable lithology that has undergone recrystallization to microspar.

The relationship between the depositional eogenetic features that suggest a shallow turbulaent depositional environment and the area of optimum oil production now becomes clear. Shallow-water sediments subject to intermittent periods of emergence - i.e. those that formed rocks bearing tepee structures - are most likely to be effected by meteoric water and therefore by fresh-water flushing leading to microspar aggradation. In turn, aggrading neomorphism has produced pore systems that are characterized by pore throats of uniform size with an insignificant proportion of very fine porosity, and that hence afford excellent oil recovery. The injection and ejection curves of these samples are similar in shape. Kent *et al.* (1982) have suggested that the more closely the ejection curve mimics the shape of the original injection curve, the better the enhanced recovery yield.

Conversely, the most common capillary pressure curves in the low permeability areas (Fig. 11) are typically steep with a plateau of mercury invasion into pores less than 1µm in diameter (Fig. 14). Thin sections reveal that the only feature common to all the the available samples in this curve group are microstylolitic sutures at grain to grain contacts. The very fine plateau of mercury invasion appears to be due to entry of micropores along the plane of trhe stylolites. Steeply inclined curves related to microstylolitization, although most common, comprise only 26 percent of the total samples from the low permeability area. The remaining samples are spread across all the other groups, but are confined to those lithologies that have either very few mega-pores so that many of the intramatrix pores remain relatively ineffective, or large pores that comprise a very large percentage of the porosity. The grain boundary microstylolites do not affect any cement phases; this suggests that compaction causing pressure solution occurred before matrix consolidation was complete. Despite this late stage of matrix consolidation, only two of the samples are characterized by entry pressures less than minimum pressure, revealing that although matrix cementation was incomplete the prevailing current regime was insufficient to develop mega-pores by eroding the unlithified matrix. Fresh water flushing, as interpreted from the matrix cyrstal size, was minimal. Water conditions during deposition in the 'low permeability' area were therefore neither as shallow, nor as turbulent as interpreted for the 'high permeability' area of optimum hydrocarbon production.

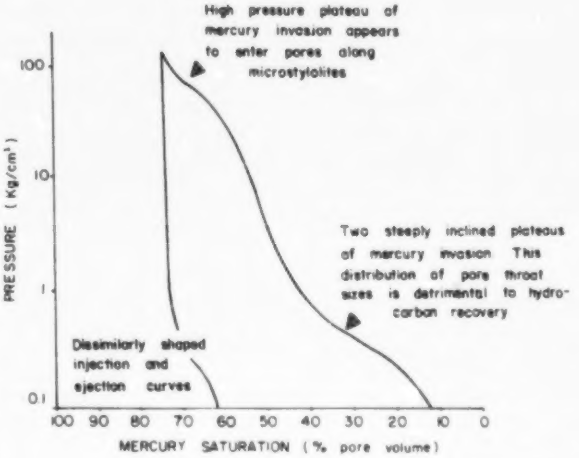

Fig. 14 - Capillary pressure curves from a sample within the area of low permeability lithologies.

LOCATION OF THE AREA OF OPTIMUM OIL PRODUCTION

Crabtree (1982) using Shark Bay, western Australia, as an analogue to the Innes area, found that in the Holocene setting water depths are shallowest and sediment accumulations thickest adjacent to the channel (Davis, 1970). In contrast, the

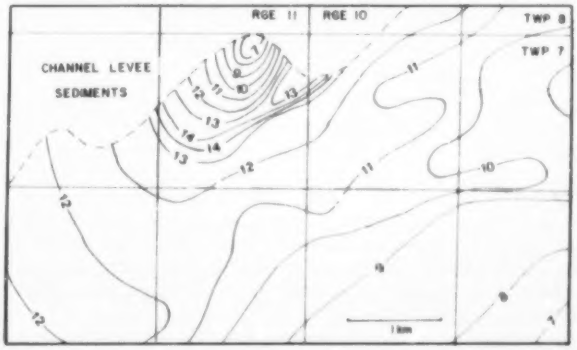

Fig. 15 - Isopach Map of IFPB-2. Contour values in metres (from Crabtree, 1982).

isopach map of IFBP-2 (Fig. 15) reveals that the thickest accumulation of sediments does not occur immediately adjacent to the channel levee deposits.

The IFBP-2 depositional unit is 14 m thick in the northwest portion of the field. However, as discussed previously, this is not the site of the shallowest waters. The area of optimum oil production is approximately bounded by the 12 and 9 m isopachs. The 11 m isopach, which encloses the centre of the high permeability area, delineates an incomplete domal thickening.

Channel levee sediments are characteristic of IFBP-1 as well as IFBP-2, indicating that the Shark Bay type of tidal channel had been established before the deposition of IFBP-2. Bathymetrically positive features in Shark Bay become the substrate for overlying shallow-water deposits, a phenomenon that can be used to explain the location of the shallow-water area now the site of optimum fluid recovery within the Innes Field. In both places, shallow-water areas are sub-parallel to the channel deposits. Davis (1970) notes two features in Shark Bay that are oriented either subparallel or diagonally to the tidal channels: sand bars on the levee surfaces, and crevasse deposits associated with levee breaching. The large size of the area of optimum production in the Innes Field suggests that sedimentation of IFBP-2 deposits was controlled by crevasse splay deposits in IFBP-1; sand bars would have been too small. The location of the tidal channel at the northern margin of the pool is the same in both IFBP-1 and IFBP-2. Channel and levee type deposits are also found within the area of optimum production but only in sediments of IFBP-1. A thin (1.3 m) but distinctive interval of cross-bedded carbonate and quartzose sands, similar to the channel-fill deposits described by Crabtree (1982), appears to mark the incursion of crevasse splay sediments into the northeasterly extreme of the shallow-water area delineated by tepee structure distribution and by related sediments (Fig. 7). The crevasse was a short-lived feature as its deposits are thin, and are directly overlain by algally laminated dolomitic sediments containing algal rip-up clasts. The sediments are probably levee type deposits.

In conclusion, crevasse splay deposits in IFBP-1 appear to control the site of tepee formation, meteoric flushing and therefore the location of optimum fluid production for IFBP-2 because it provided a high-lying substrate upon which the shallow-water deposits of IFBP-2 were laid down.

OIL PRODUCTION: THE INTERACTION OF STRUCTURAL POSITION AND PORE GEOMETRY

IFBP-2 is a structural-stratigraphic trap, in which the oil accumulation is centred over a domal structure and is confined in the northwest by reduced permeability. Oil distribution within the pool is determined by structure and stratigraphy but oil production is controlled, at least in part, by the nature of the pore system. In structural traps, optimum oil recovery is commonly assumed to be from the crest of the structure. This is not true at Innes, where the area that produces the most oil and least water lies to the southeast of the crest (Fig. 6), also the location of the porosity parameters with the greatest potential for oil recovery (Fig. 11).

Pore geometry Divisions II and III characterize the area of optimum oil production but are not restricted to it, covering most of the southern and eastern areas of the pool. This entire area occurs within the pool but the highest oil production is confined to the central part of the pool because of the elevation of the oil/water transition zone. The southern boundary of the pool, the theoretical oil/water interface, coincides with the -726 m structural contour in the south and east. The southern limit of the optimum production area roughly follows the −718 m structural contour which indicates that in the southeast the transition zone is approximately 8 m thick. In the southwest the wells are not perforated within IFBP-2 (Fig. 6); fluid production data are therefore unavailable, so the extent of the transition zone cannot be observed. The porosity contour map (Fig. 10) shows that in the southwest virtually all porosity values are less than 14 percent, whereas all porosity values within the optimum production area exceed this figure. Arps (1964) noted that the height of capillary rise is determined by pore diameters, water rising much higher above the free water surface in rocks with low porosities and permeabilities than in those that are porous and permeable. Therefore, whatever the thickness of the transition zone in the east, it will be thicker in the west.

Although pore geometry is one of the major factors controlling oil production in IFBP-2 it is not the only control. Areas of poor pore geometry are in places marked by high oil production due to their structural position within the pool. Only the eastern portion of the optimum production area falls within the zone of highly permeable lithologies characterized by pore geometry Divisions II and III (Fig. 11). Wells in this area are marked by low water-cut and excellent annual oil production (4400 barrels per year). To the west the optimum production area narrows. It is also characterized by a low water-cut but annual oil production is lower (3300 to 4400 barrels per year). Samples from the west are included within pore geometry Division IV, which typically has low or undetectable permeabilities, but their position within the pool above the oil/water transition zone places them inside the optimum production area because of the thick oil column.

Summary and Conclusions

Innes Frobisher Beds Pool-Two is a structural-stratigraphic trap, in which hydrocarbon distribution is controlled partly by an incomplete domal structure, partly by facies-related permeability changes. Wells with the highest oil recovery and lowest water-cut are not located at the crest of the structure but down-dip toward the southeast in rocks that contain horizons of vadose pisoids and that are dominated by mega-pores. The vadose pisoid horizons were clearly deposited in extremely shallow water, and were periodically exposed. Mega-pores are thought to have been formed by eogenetic erosion of uncemented matrix following differential matrix cementation, also suggestive of syn- and immediately post-depositional turbulence in shallow water.

Contour maps of petro-physical parameters and the distribution of statistically derived pore geometry groups together show that the shallow water deposits occupy the most favourable location with respect to potential oil recoverv. Comparision of capillary curves with thin sections of related rock specimens reveals recrystallization of micrite matrix to coarse microspar possibly due to flushing by meteoric waters. Fluid accessibility to fine porosity was enhanced through mega-pores, which also create a favourable pore geometry for optimum hydrocarbon recovery. The shallow water/ optimum production area is not immediately adjacent to the tidal channel deposits. Its location is thought, rather, to be determined by an original topographic high caused by crevasse splay deposits in the underlying sediments.

Hydrocarbon production in the Innes Field is soley dependant neither on structural control nor on pore geometry control, but on a combination of both. Some areas of potentially poor pore geometry are marked by good oil production due to structural position within the pool. Conversely, a large proportion of sediments with highly favourable pore geometry falls within the oil/water transition zone. Pore geometry also plays a role in the distribution of hydrocarbons within the pool; the westward decrease in pore size and premeability causes the oil/water transition zone to rise stratigraphically higher within IFBP-2.

Despite the fact that the nature of the IFPB-2 reservoir in the Innes Field does not appear to lend itself to conventionally enhanced recovery schemes such as water flooding, the writer is of the opinion that developing pore geometry models for reservoirs of this type can be useful for establishment of less conventional enhanced recovery projects.

Acknowledgements

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GEOLOGY AND RESERVOIR PROPERTIES OF THE WEYBURN FIELD, SOUTHEASTERN SASKATCHEWAN

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ABSTRACT

The Weyburn Field is located at the western periphery of the prolific Midale-Steelman oilfield trend along the northeastern flank of the Williston Basin. Hydrocarbon production is from the Mississippian Midale Beds. These beds constitute a small portion of a thick succession of Mississippian cyclic sediments.

The Midale Beds have been divided into the Frobisher Evaporite and the Midale carbonate. The Midale Carbonate can be further subdivided on the basis of petrophysical well log response and general lithology into two lithostratigraphic units. These units are referred to here as the upper "Marly" and lower "Vuggy" zones. Sediments of the "Vuggy" were deposited in an open marine moderate to high energy environment, while "Marly" sediments were laid down in a shelf interior, restricted low energy setting. The Midale Beds dip southward towards the centre of the Basin. Post-Mississippian erosion has truncated the entire Midale section immediately north of the field. Oil is trapped by a combination of structural, diagenetic and stratigraphic elements.

Variation in the types of diagenesis affecting both lithostratigraphic units has led to the formation of different porosity types. The "Vuggy" unit is characterized by the presence of intergranular, moldic and vuggy porosity, whereas the "Marly" unit is dominated by intercrystalline porosity.

As a result of the varying types and areal distribution of the porosity, a significant difference in reservoir characteristics between the two zones is apparent. Consequently, the units each require a separate approach with regard to completion, production and enhanced recovery schemes.

INTRODUCTION

The Weyburn Field of southeastern Saskatchewan, as outlined by Saskatchewan Energy and Mines, covers portions of Townships 5, 6, and 7, Ranges 11, 12, 13, and 14 W2M. The field is found near the present northwestern edge of the Midale-Steelman oilfield trend (Fig. 1). Oil accumulation is in the Midale Beds of the lowermost Mississippian Charles Formation (Madison Group).

The discovery well, Central Del Rio Ralph No. 14-06-07-13W2M, was drilled to a depth of 1,562 m and completed as a Midale Beds oil producer in 1955. Within the designated field boundary, approximately 850 wells have been drilled to date. The greater part of the pool was unitized in 1963 and an inverted nine-spot waterflood scheme was implemented in 1964. At the end of 1983, the Weyburn Unit included 477 producing wells, 138 injectors, 52 miscellaneous wells (water source, pressure observation, temporarily shut in, etc.) and 24 abandoned wells.

GEOLOGY

Regional Setting

The Mississippian Madison Group of the Williston Basin contains a 400 to 700 m thick section of carbonate and evaporite sediments (Kent, this volume). The sedimentation pattern is typical of a major upward shoaling sequence, deposited as a thick basinward migrating wedge of sediments. Superimposed on this system are individual cycles of transgressive-regressive pulses, which are the result of sea level fluctuations (Wilson, 1975).

The Upper Madison carbonates of southeast Saskatchewan were deposited in a relatively broad, shallow marine environment (Kent, 1983, this volume). Slight changes in sea level resulted in widespread and fairly uniform depositional changes. The tops of cycles are often characterized by argillaceous marker beds with distinct geophysical log signatures and can be considered as "practical time lines" (*cf* Wilson, 1984, Kent, this volume). The Madison Group in southeast Saskatchewan has been subdivided into a series of marker-defined stratigraphic units termed "Beds", as il-

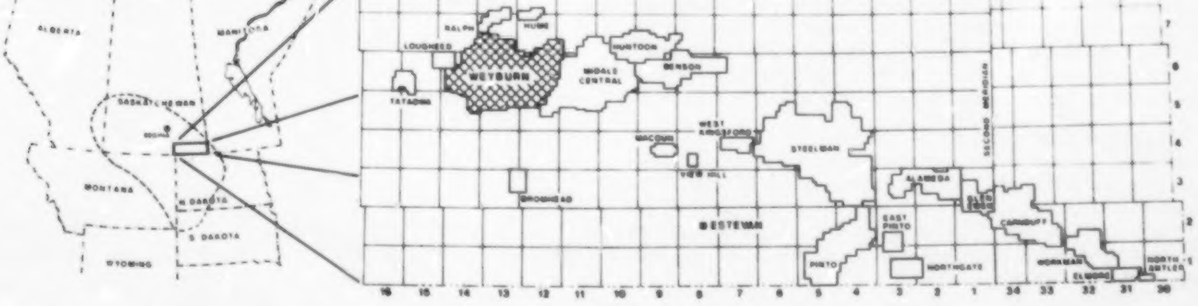

Fig. 1 - Location of the Weyburn Field and other fields in the Midale Trend.

lustrated in Figure 2 (S.G.S., 1956, Fuzesy, 1960). Continued subsidence resulted in the southward dipping strata observed today. Subsequent post-Mississippian erosion truncated progressively older Mississippian strata northward across southeastern Saskatchewan, creating the present day Mississippian subcrop pattern (Fuzesy, 1960).

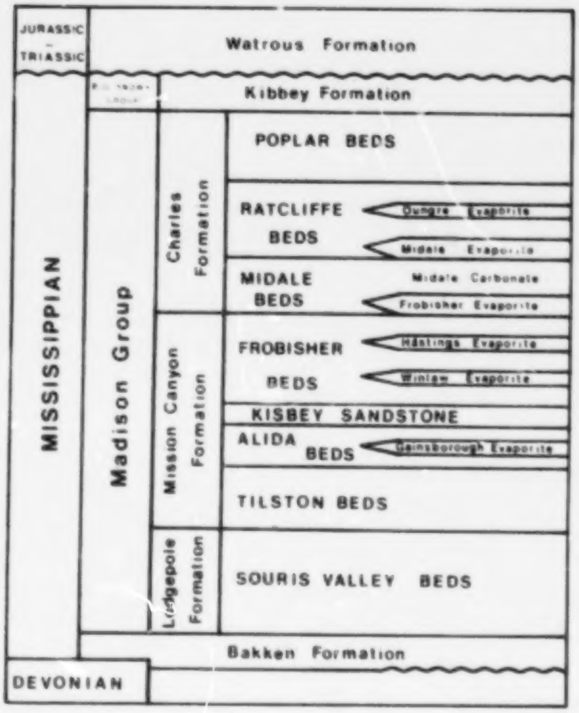
JURASSIC - TRIASSIC
Watrous Formation
MISSISSIPPIAN
Kibbey Formation
Madison Group
Charles Formation
POPLAR BEDS
RATCLIFFE BEDS
Dungre Evaporite
Midale Evaporite
MIDALE BEDS
Midale Carbonate
Frobisher Evaporite
Mission Canyon Formation
FROBISHER BEDS
Hastings Evaporite
Winlaw Evaporite
KISBEY SANDSTONE
ALIDA BEDS
Gainsborough Evaporite
TILSTON BEDS
Lodgepole Formation
SOURIS VALLEY BEDS
Bakken Formation
DEVONIAN

Fig. 2 - Mississippian stratigraphy of southeastern Saskatchewan

Weyburn Area

The stratigraphy in the Weyburn area is summarized in Figure 3. The Midale Beds are comprised of the Frobisher Evaporite and the Midale carbonate. Within the field boundary, the depositional edge of the Frobisher Evaporite is indicated by a lateral change from massive dense anhydrite with thin interbeds of dolomitic mudstones in the northeast to dolomitic, often argillaceous lime mudstones and wackestones in the southwest (Fig. 4). The sequence marks a distinct facies change from highly restricted, hypersaline conditions in the northeast, to a somewhat more open lagoonal facies in the southwest. The Frobisher Evaporite attains a thickness of 9 m along the northern field edge and reaches a zero edge in the central field area. Beyond this margin, thin isolated pockets of anhydrite are occasionally encountered (Fig. 4).

Directly overlying the Frobisher Evaporite is a thin, very argillaceous marker horizon containing small mud intraclasts and some algal fragments with common iron oxide stains. This zone is interpreted to be a remnant of a transgressive lag deposit; it marks the transition from the evaporite facies to more normal marine conditions under which the Midale carbonate was deposited.

The Midale carbonate in the Weyburn area is subdivided into two distinct lithostratigraphic units, referred to as "Vuggy" (lower) and "Marly" (upper) (Fig. 3). In the "Vuggy" unit, six lithologic types can be recognized: 1) argillaceous lime mudstone-wackestone, 2) wavy laminated mudstone-wackestone, 3) bioturbated mudstone-wackestone, 4) skeletal packstone, 5) peloidal and mixed peloidal-skeletal packstone and 6) peloidal packstone-grainstone. On the basis of lithologies, the "Vuggy" unit can generally be divided into two zones. The lower portion is thin bedded, slightly argillaceous lime mudstone-wackestone, interbedded with occasionally porous bioclastic and/or peloidal packstones. The upper portion of the "Vuggy" unit consists of interbedded peloidal and bioclastic packstones and rare peloidal (originally oolitic) grainstones. Coarser beds are frequently separated by relatively thin lime mudstones and wackestones. The top of the "Vuggy" unit is generally formed by a "non-porous" lime wackestone bed, which clearly separates the porous "Vuggy" sections from the overlying "Marly" unit. Throughout the "Vuggy" unit, bed thicknesses are highly variable, ranging from 10 cm to 2 m. Bioturbation of the lime mudstones-wackestones is shown by local mottled appearance, but burrowing has more commonly homogenized the otherwise wavy laminated sediments. Vertical to oblique hairline fractures lined with anhydrite or calcite are commonly observed. Abundant secondary anhydrite is common also. It occurs as brown platy clusters and veinlets, and is interpreted to be of metasomatic origin (Kendall *et al.*, 1978).

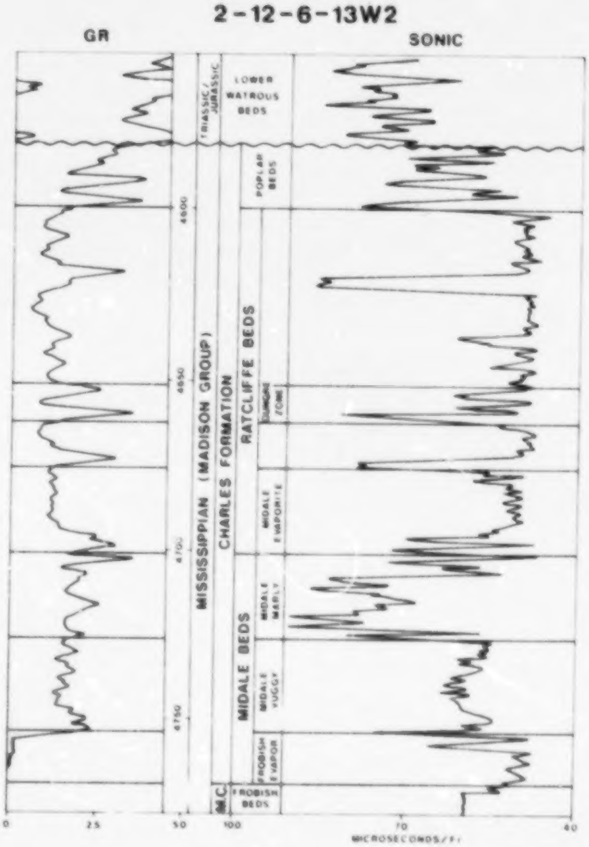

Fig. 3 - Upper Madison Group (Charles Formation) stratigraphy and characteristic log response in the Weyburn area.

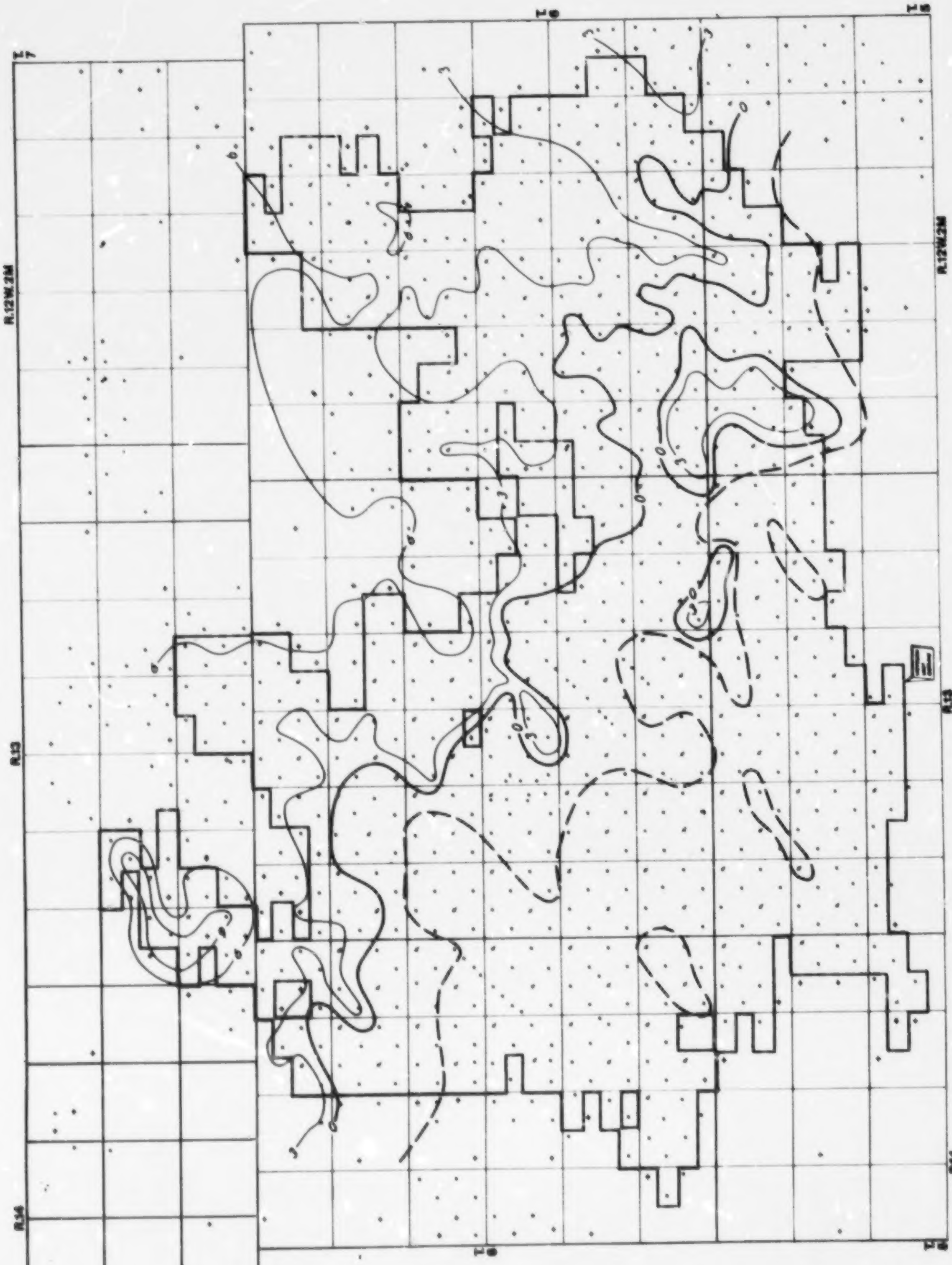
T7
R.12W.2M
R.13
R.14
T6
T5
R.12W.2M
R.13
R.14
T6
T7
0
3

Fig. 4 - Isopach of the Frobisher Evaporite (contour interval 3 m) showing the depositional edge and area of facies change (between the zero isopach and the dashed line).

The "Vuggy" megafauna assemblage includes corals (*Kakwiphyllum*, *Syrinopora*), brachiopods (*Spirifer*) and crinoids. In addition, ostracods and foraminifera are recognizable. The skeletal limestones are generally composed of shell fragments, crinoids and algal debris.

Comparison of vertical successions across the field reveals a complex distribution of lithologies. This intricate distribution makes a specific environmental interpretation somewhat difficult, but in general, it appears that the energy level increases towards the top, culminating in the deposition of skeletal and oolitic packstones or grainstones. The oolitic (peloidal) grainstones represent a migrating shoal environment. The depositional environment is reflected by the "Vuggy" unit thickness patterns (Fig. 5). The relatively wide range in thickness (10 to 20 m) and a "patchy" aereal distribution of thick intervals suggest the development of coarse grained shoals near or at the top of the sequence where the "Vuggy" is thickest.

The "Marly" unit is predominantly composed of microcrystalline, slightly argillaceous dolomite. Many of the original sedimentary structures are obscured due to diagenetic processes and by heavy residual oil saturation. Remnants of original sedimentary structures include fine horizontal and wavy lamination. Occasionally, small intraclasts (originally lime mudstone) are present. Over the majority of the pool, the "Marly" unit can be divided into two zones, separated by a non-porous fragmental packstone approximately 2 m thick. Similar limestone stringers are common, although thinner (10 to 50 cm) and less extensive laterally.

The thickness of the "Marly" unit is fairly uniform (average 7 m), although a slightly thicker section is found trending northeast-southwest through the central field area (Fig. 6). In addition, the "Marly" unit thins slightly to the north. This coincides with a lithologic change in the Upper "Marly" from microcrystalline dolomite to a laminated cryptocrystalline dolomite. The "Marly" unit in the northeast-southwest trending zone is composed of various lithologies. Generally individual beds are thin (5 to 50 cm) and comprise laminated mudstones interbedded with coarse skeletal packstones, containing fragments of crinoids, brachiopods and corals. Also, sequences of laminated argillaceous lime mudstone to grainstone occur. The mud matrix of all lithologies is preferentially dolomitized. Sedimentary structures include small rip-up clasts, escape (?) burrows, tilted laminae (possibly due to slumping), small scale scour surfaces and minor cross lamination.

The lithologies, sedimentary structures and trend direction (virtually perpendicular to the inferred paleo-coastline of Kent, 1983) suggest that this (higher energy) zone represents a tidal channel. By contrast, the remaining "Marly" unit lithologies, originally deposited as mudstones-wackestones, suggest deposition in a low energy and fairly restricted subtidal environment. The limestone bed that separates the Upper "Marly" section from the Lower "Marly" probably reflects a temporary return to more normal marine conditions.

The Midale Beds are overlain by the Midale Evaporite of the lowermost Ratcliffe Beds. The contact between the two units is gradational. Arbitrarily, the top of the Midale Beds is taken at the top of a distinct gamma-ray deflection that can generally be traced throughout the field (Fig. 3). The Midale Beds-Midale Evaporite facies change is characterized by an upward increase in interlaminated dolomite, dolomitic shale and bedded anhydrite. Clear indications of subaerial exposure in this gradational zone have not been recognized to date. The environment was highly restricted, reaching hypersalinity, as indicated by the evaporite deposition and the absence of bioturbation (suggesting an environment hostile to benthic faunas). Sediment accumulation obviously took place subaqueously. However, the Midale Evaporite itself is comprised of nodular-enterolithic anhydrite with numerous structures indicative of subaerial exposure and thus forms a typical sabkha sequence (Kaldi, J, pers. comm.).

Structure

The Mississippian strata in the Weyburn area dip southward (8.3 m/km), forming a broad homoclinal feature (Fig. 7). Superimposed on this trend are major structural irregularities, commonly oriented in a northeast-southwest direction. Comparison of structure contours (Fig. 7) with "Marly" isopachs (Fig. 6) illustrates that the directional trends found today were also present during Midale time, influencing the depositional configuration. Although some structural irregularities may be attributed in part to Prairie Evaporite salt tectonics, it is felt that the consistent directional trends, also recognized regionally, are related to basement tectonics (*cf.* Kent, this volume).

Reservoir Characteristics

A variety of pore types are recognized throughout the Midale Beds of the study area. The "Vuggy" is characterized by the presence of intergranular, intragranular, moldic and vuggy porosity (Fig. 8). Intergranular and intragranular porosity types dominate the peloidal and mixed peloidal bioclastic packstone-grainstone facies. Moldic and vuggy porosity are usually confined to the wackestone facies. Pore interconnection is generally good in the case of intergranular porosity. Moldic and vuggy porosity is associated with low matrix permeability, unless fractures are present. The porosity of the "Vuggy" unit averages 7% and the permeability, though highly variable (0.1 - 100 mD), averages 1 mD. By applying petrophysically derived porosity and permeability thresholds of 6% and 0.5 mD respectively, average reservoir porosity is calculated to be 9% with a permeability (still highly variable) of 4 mD.

The "Marly" unit is characterized by intercrystalline porosity (Fig. 9). Pore size distribution is fairly uniform, with pore diameters on the order of 5 um. Microvugs are also common. The microcrystalline dolomites exhibit average porosity of 17% and average permeability of 2 mD. By applying petrophysically derived thresholds of 16% and 1 mD, the average reservoir parameters for the "Marly" unit are 21% and 3 mD.

Diagenesis

Although primary sedimentary processes are important to the distribution of potential reservoir rock, porosity development and occlusion in the Midale Beds are the result of multistage, variable diagenetic processes. The intricate porosity distribution in the Midale Beds is the result of a complex diagenetic history.

Postdepositional processes in the "Vuggy" unit began with micritization of allochems, probably related to biochemical activity in a shallow marine phreatic zone (*cf.* Longman, 1982). Following this, changes in the chemical composition of the interstitial water, probably as a consequence of fresh water influx, caused leaching of aragonitic skeletal fragments, resulting in moldic porosity. Subsequent precipitation of sparry calcite partly occluded molds and intragranular pores. It is thought that the introduction of highly saline fluids undersaturated with respect to calcium carbonate resulted in

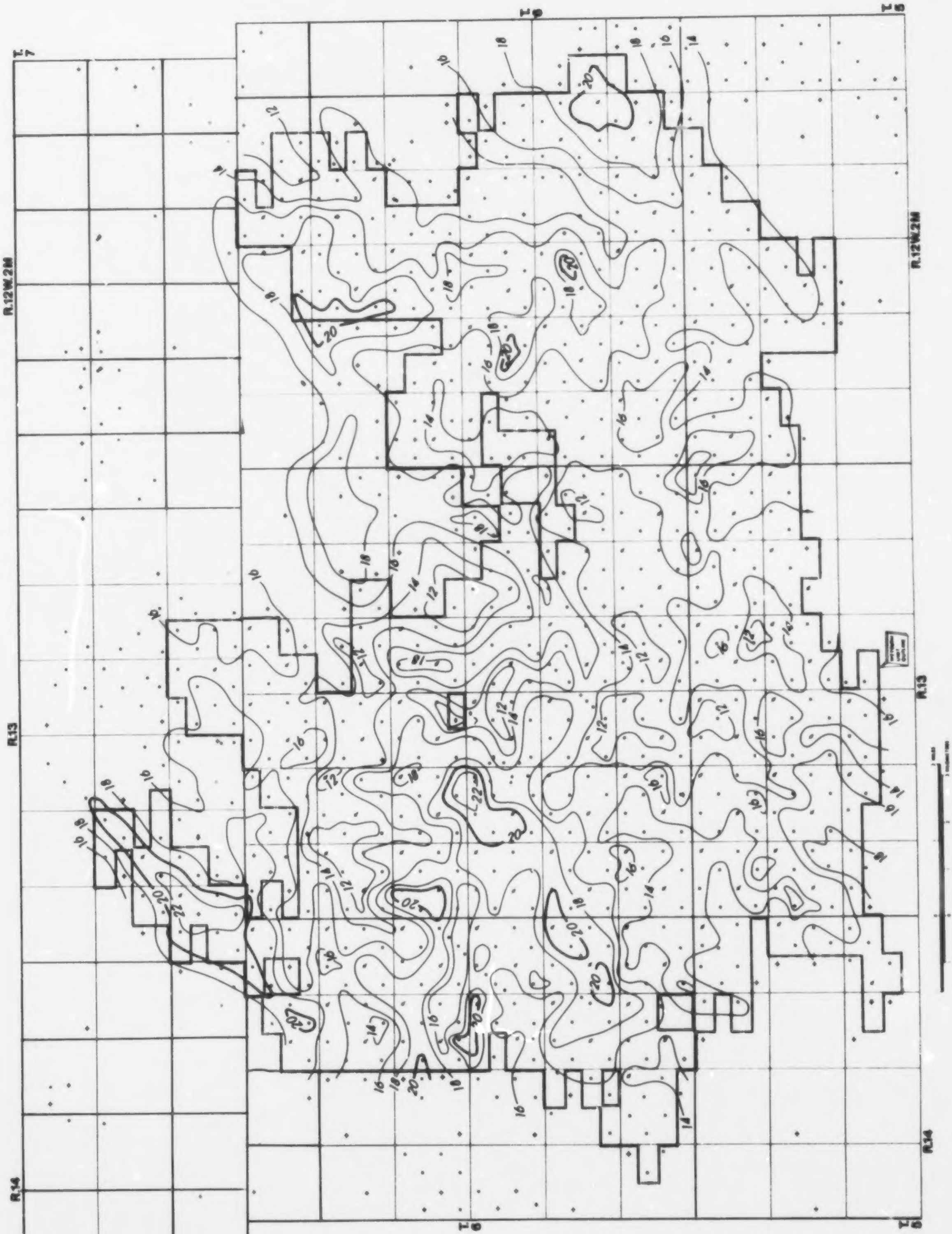
T.7
T.6
T.5
R.12W.2M
R.13
R.14
10
12
14
16
18
20
22

Fig. 5 - Isopach of the Midale "Vuggy" unit (contour interval 2 m).

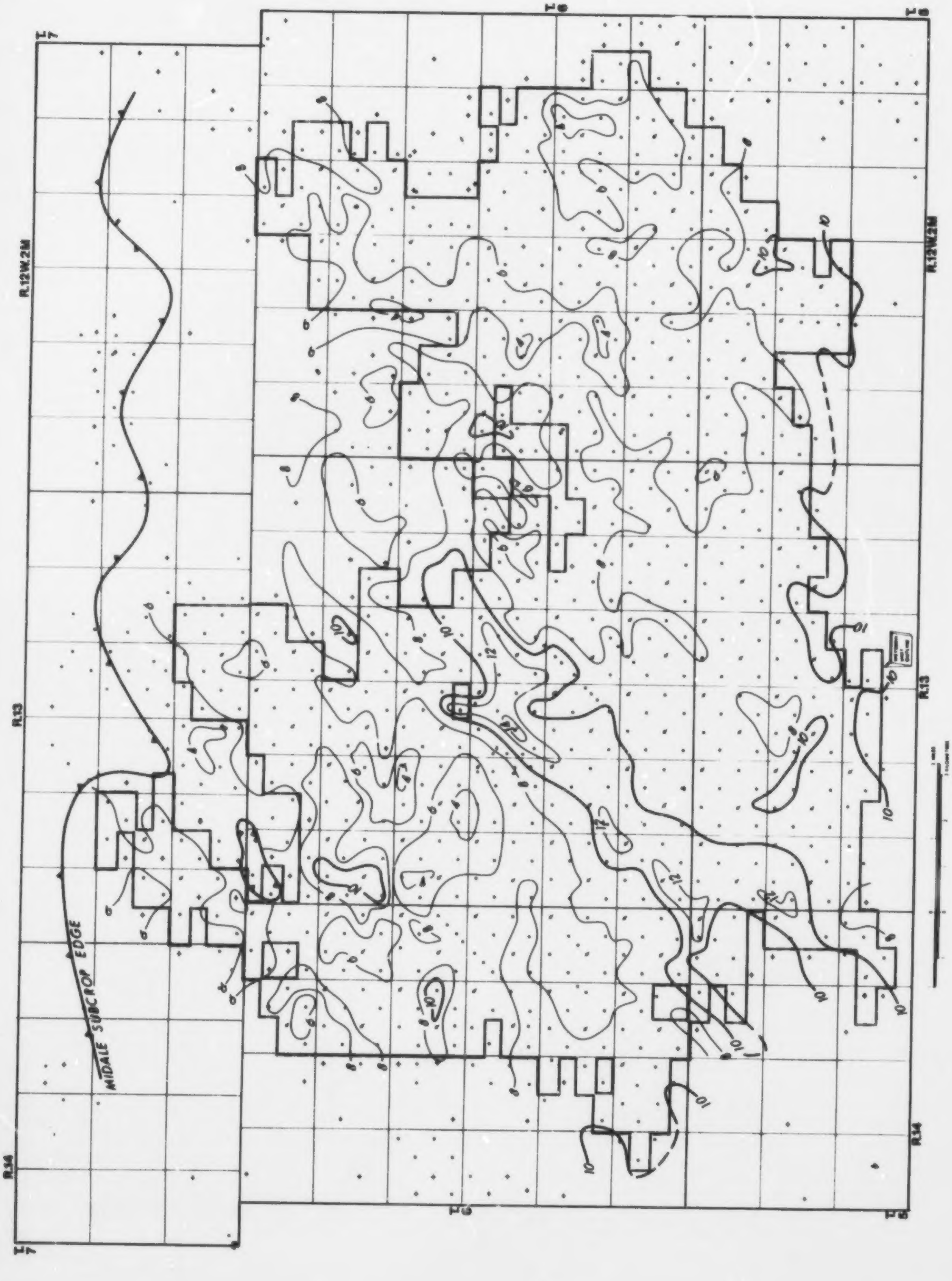
T7
T6
T5
R.12W.2M
R.13
R.14
MIDALE SUBCROP EDGE
6
8
10
12

Fig. 6 - Isopach of the Midale "Marly" unit (contour interval 2 m).

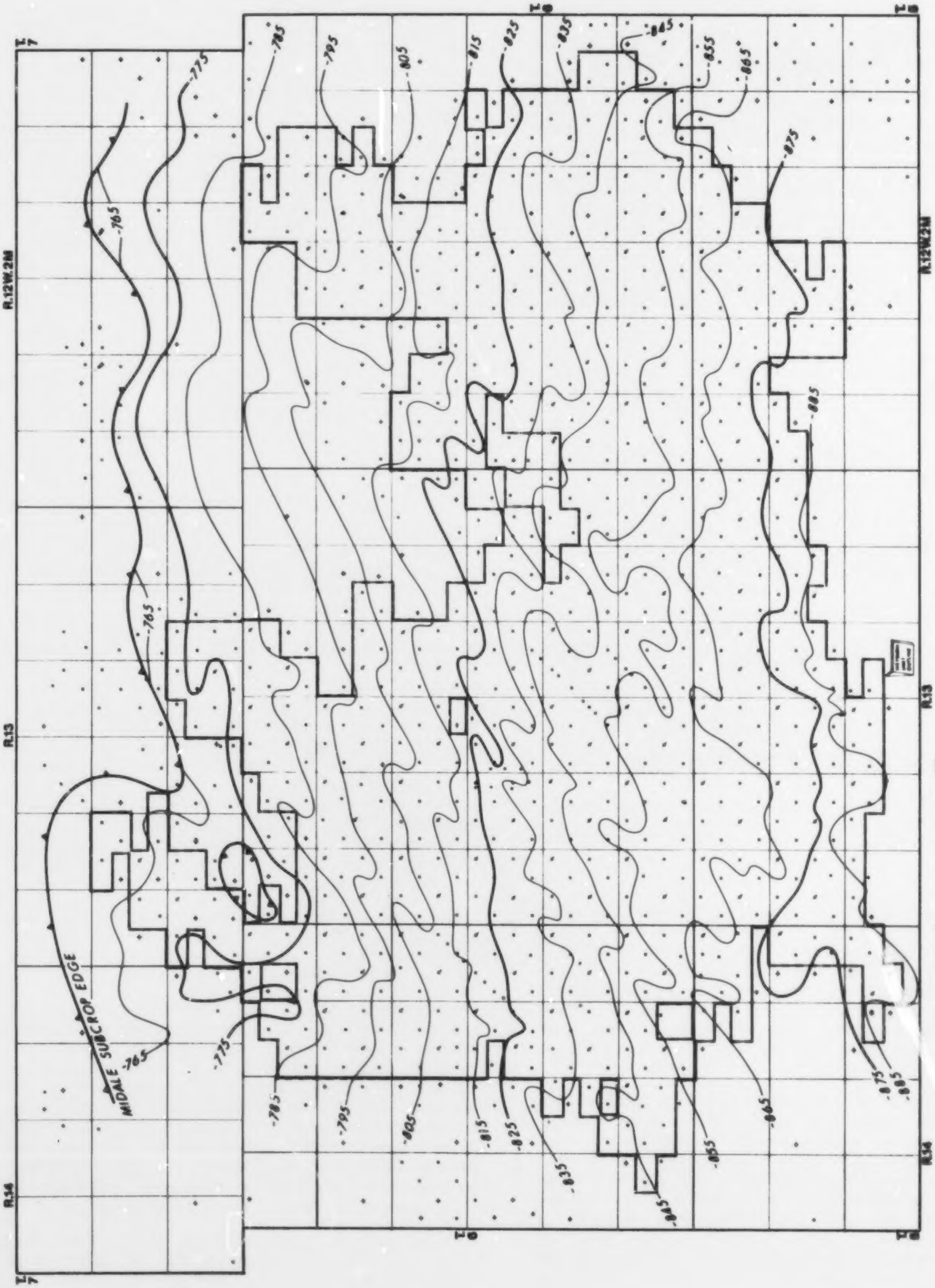
T.7
T.8
R.12W.2M
R.13
R.14
MIDALE SUBCROP EDGE
-765
-775
-785
-795
-805
-815
-825
-835
-845
-855
-865
-875
-885

Fig. 7 - Structure contours on the Midale Beds (contour interval 10 m).

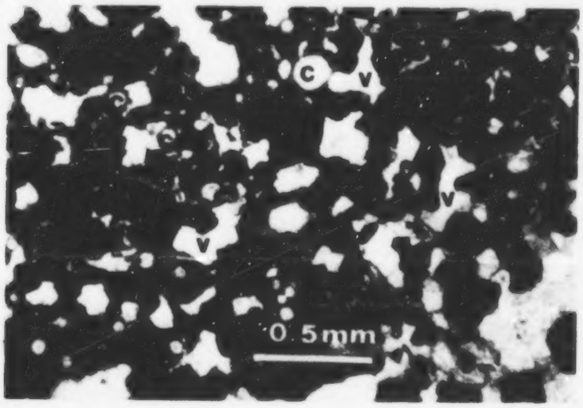

Fig. 8 - Photomicrograph of the Midale "Vuggy" unit, showing porous peloidal grainstone (-grapestone) interpreted to represent a shoal environment. White rounded fragments (c) are perhaps leached and subsequently cemented ooid cores. Porosity is intergranular (i) and vuggy (v), plane polarized light, 35 ×, porosity 17%, permeability 80mD; CDR Goodwater 16-36-5-13W2, 1448 m.

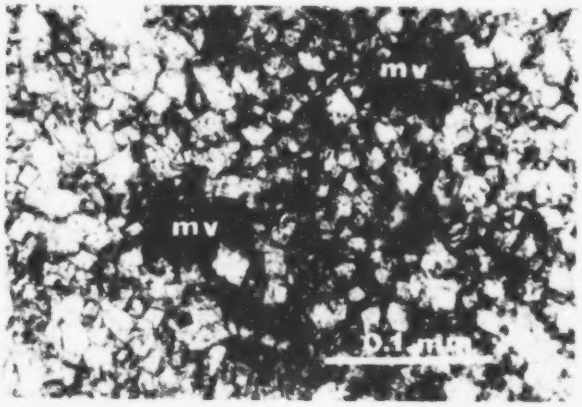

Fig. 9 - Photomicrograph of the Midale "Marly" unit, showing intercrystalline and microvuggy (mv) porosity in microcyrstalline dolomite. Plane polarized light, 250 ×, porosity 21%, permeability 6 mD; HB Weyburn 14-26-5-13W2, 1449 m.

enhancement of preserved molds and intergranular pores, creating vuggy porosity. This process is thought to be a relatively late diagenetic event. Clear calcite and/or anhydrite lining vugs and hairline fractures, which formed after significant burial, postdate the events above. The last diagenetic event affecting the "Vuggy" unit is the formation of brown metasomatic anhydrite, probably associated with Late Cretaceous hydrocarbon emplacement (Kendall and Walters, 1978).

Dolomitization is the dominant diagenetic event affecting the "Marly" unit. The areal distribution of dolomite (regionally persistent along strike but discontinuous in dip direction) suggests that early alteration of the lime mudstones and wackestones of the "Marly" unit took place by a process of seepage refluxion as described by McKenzie *et al.*, (1980). High evaporation in the intertidal-supratidal region during Midale Evaporite deposition resulted in brines with high Mg^{2+}/Ca^{2+} ratios and relatively low SO$_4^{2-}$ concentration due to gypsum precipitation. These brines moved through the sabkha (Midale Evaporite) sediments into the "Marly" unit, driven down depositional slope by the hydrostatic head created by periodic water accumulation on the sabkha ("flood recharge", stage I of McKenzie *et al.*, 1980). The ample supply of Mg^{2+}, coupled with low SO$_4^{2-}$ caused dolomitization.

As the brine moved seaward, dolomitizing capacity was reduced due to a decrease in Mg^{2+}/Ca^{2+} ratio as dolomite precipitated. In this way a belt consisting of partially dolomitized carbonates developed parallel to coastal strike; it was bound to the north by completely dolomitized sediments and to the south by virtually undolomitized limestones. This setting represents the depositional system at one point in geological time. In a prograding sabkha situation, one would expect (because of continuing flood recharge and subsequent refluxion) the "Marly" unit to be completely dolomitized. that this is not the case can probably be attributed to the contemporary formation of an effective seal between the "Marly" unit and the Midale Evaporite, preventing any additional dolomitization of the "Marly" sediments. The transitional zone between the "Marly" unit and the Midale Evaporite was possibly dolomitized until permeability became non-effective and further vertical communication was prevented. Another explanation might be that as the Midale Evaporite prograded, it became impermeable due to extensive internal anhydritization, and flood waters could not penetrate the sabkha sediments.

Another important aspect in the Midale Beds of the Weyburn area is the penetration depth of dolomitization. As discussed earlier, the degree of dolomitization would decrease (laterally as well as vertically) because the Mg^{2+}/Ca^{2+} ratio is reduced when dolomite is formed. Hence a gradual downward decrease in dolomitization would be anticipated. However, the contact between the "Marly" dolomite and the "Vuggy" limestone is sharp. In the "Marly" unit size and distribution of dolomite crystals are uniform and no vertical change is evident. These observations suggest that during dolomitization of the "Marly" unit, a limestone barrier existed between the two units, precluding any significant dolomitization of the "Vuggy" sediments. To a certain degree this is confirmed by the fact that the "Marly" and "Vuggy" units are presently separated by a non-porous wackestone (see above). Early cementation of this bed may have created an impermeable barrier through which no dolomitizing fluids could percolate. Similar observations were made in the Ordovician Red River Formation by Longman *et al.*, (1983).

After dolomitization of the "Marly" unit, leaching of the remaining lime mud matrix and some fine shell debris enhanced the porosity and permeability, which resulted in the present day combination of intercrystalline and microvuggy porosity.

The suspected change from microcrystalline reservoir dolomite northwards into cryptocyrstalline non-reservoir dolomite probably reflects an increasing degree of dolomitization updip. Confirmation of this hypothesis will require extensive thin section study. However, the observations made to date show similarity with settings that have been described in the Abu Dhabi coastal region (McKenzie *et al.*, 1980). Chemically comparable processes, resulting in reservoir and non-reservoir dolomites have been reported from the Ordovician Red River Formation (Longman *et al.*, 1983) and the Oungre Zone of the Ratcliffe Beds (Hartling *et al.*,1982).

The last significant stage in diagenesis of the "Marly" unit before hydrocarbon emplacement was the formation of replacement anhydrite, causing minor porosity occlusion.

Formation Evaluation

Tne Midale Beds within the Weyburn Unit were partially or completely cored in 441 wells and most were analyzed by conventional methods. The log suite available is fairly limited and the absence of porosity logs in many cases prevents proper reservoir evaluation.

In order to establish reservoir parameters and their distribution, correlation of available core data and logs is necessary. The relationship between core and log data of the "Marly" and "Vuggy" units differs, especially with regards to permeability. This can be attributed to the dissimilar pore characteristics discussed above.

Single well correlation, derived from log-core porosity crossplots, is generally good (when proper porosity logs are available). Slight variations from well to well (due to wellbore conditions, drilling muds used, etc.) make group correlations less accurate. Extrapolation of porosity and permeability values over noncored intervals using single well models is therefore associated with a reasonable degree of confidence. An example is graphically presented in Figure 10. When no core is available, group models of surrounding wells are used. Where neither porosity logs nor cores are available, values of surrounding wells are averaged and compared qualitatively with an electric log (preferably a microlaterolog).

Since the Weyburn Unit is under waterflood, no specific attention has been given to water saturation. Pre-waterflood mapping indicates that initial water saturation calculated from logs in both the "Marly" and "Vuggy" units varies between 20% and 50%. No specific trend could be established to explain this phenomenon, due to variations in reservoir type, quality and areal distribution.

Mapping of reservoir parameters shows that reservoir quality in the "Marly" unit deteriorates northward. The increase in degree of dolomitization is suggested as the probably cause. The best reservoir is found in the central portion of the field. The "Vuggy" reservoir is relatively poor in the eastern part of the field, but good reservoir rock is developed in the west-southwest. The rater intricate distribution of lithologies, coupled with complex diagenesis, makes prediction of reservoir-rock distribution difficult.

PRODUCTION

A summary of production and reservoir data is presented in Table 1. Currently, the average well within the Weyburn Unit produces 3.8 m³ per day. Initial production of the best well to date (8-31-5-13W2), located in the southern portion of the pool, was 45 m³ per day. After twenty-seven years of production, the daily average for this well is still 21 m³.

Initial production in the central field area was virtually water-free. The watercut has gradually increased through time and after 1964, the implementation of a waterflood scheme caused a drastic increase in water production (see Table 1 for current data).

Production data indicate a preferential northeast-southwest trend of fluid migration. Producing wells on trend with injec-

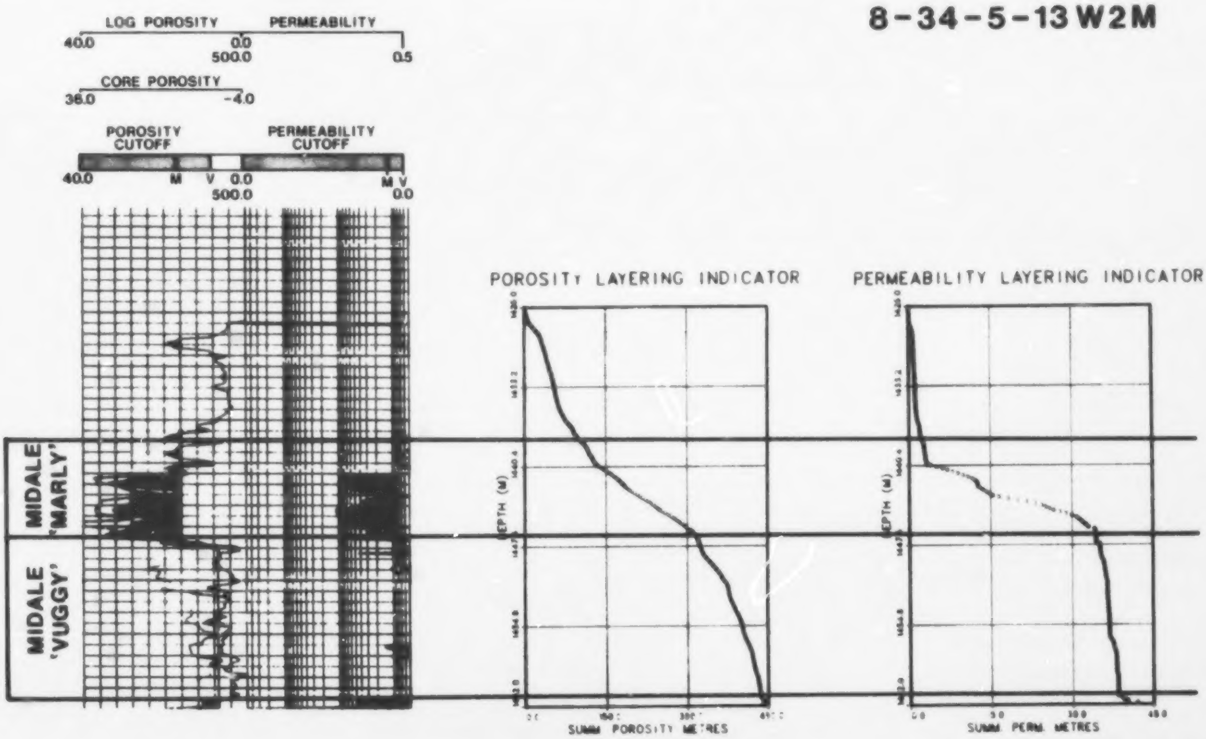

Fig. 10 - Graphical presentation of petrophysically derived reservoir parameters. Black indicates reservoir. The following regression equations - derived from single well cross-plots were used: "Marly" unit $\Delta t = 1.37\phi + 42.81$ and $\log k = 0.095\phi - 1.825$; (cut off is 16% and 1 md).
"Vuggy" unit $\Delta t = 0.66\phi + 49.58$ $\log k = 0.332\phi - 2.97$; (cut off is 6% and 0.5 md). where Δt is sonic travel time, ϕ is core porosity and log k is log porosity.

RESERVES	
INITIAL OIL IN PLACE	177.C01 (10^6 m^3)
ESTIMATED PRIMARY RECOVERY	13.5 %
ESTIMATED SECONDARY RECOVERY	16.2 %
TOTAL	29.7 %
RECOVERY TO DATE	22.6 %
PRODUCTION	
CUMULATIVE (to 31-12-1983)	40,009,028.7 m^3
YEARLY TOTAL (1983)	668,744.0 m^3
DAILY AVERAGES (1983)	1,832.2 m^3
WATER CUT (1983)	78.8 %
GOR (1983)	40.3 m^3/m^3
INJECTION	
YEARLY TOTAL (1983)	2,890,066.0 m^3
DAILY AVERAGES (1983)	7,918.0 m^3
REPLACEMENT RATIO	0.9
RESERVOIR DATA	
AVERAGE RESERVOIR DEPTH	1400 m
AVERAGE NET PAY	7.8 m
AVERAGE POROSITY	17.2 %
DENSITY	885 kg/m^3

Table 1 - Summary of production and reservoir data, Weyburn Unit, southeastern Saskatchewan.

tors show low daily oil and high watercut due to early water breakthrough after waterflood (Fig. 11). Off-trend producers are only slightly affected by injected water. The trend is in agreement with northeast trending structural irregularities (Fig. 6) and might be related to a joint system. Perhaps originally closed hairline fractures, as described earlier, are opened under injection pressures.

Currently, studies are being conducted to improve the waterflood efficiency and overall pool performance with considerations given to workover programs for existing wells and infill drilling. Studies in the U.S. (Barber *et al.*, 1983) have indicated that, by reducing well spacing in carbonate reservoirs comparable to Weyburn, recoverable reserves have increased (5% to 8%, depending on spacing area). An infill project in the Weyburn Unit ("Pattern 91", Fig. 12) shows similar results (increase of 2.4%). Six off-trend infill locations (Table 2) were drilled in 1979 by PanCanadian Petroleum (Unit Operator) and production was closely monitored. Figure 13 shows a comparison plot of group daily oil production for "Pattern 91" with and without the six infill wells. It demonstrates that production from the infill wells does not affect the decline of the original wells; therefore, incremental oil is being recovered from the infill wells. The Midale Beds form a heterogeneous reservoir within the Weyburn Field, especially in the "Vuggy" unit (Fig. 10). The reservoir is characterized by thin, discontinuous beds coupled with porosity-permeability pinchouts. Consequently, waterflood efficiency is directly proportional to well spacing.

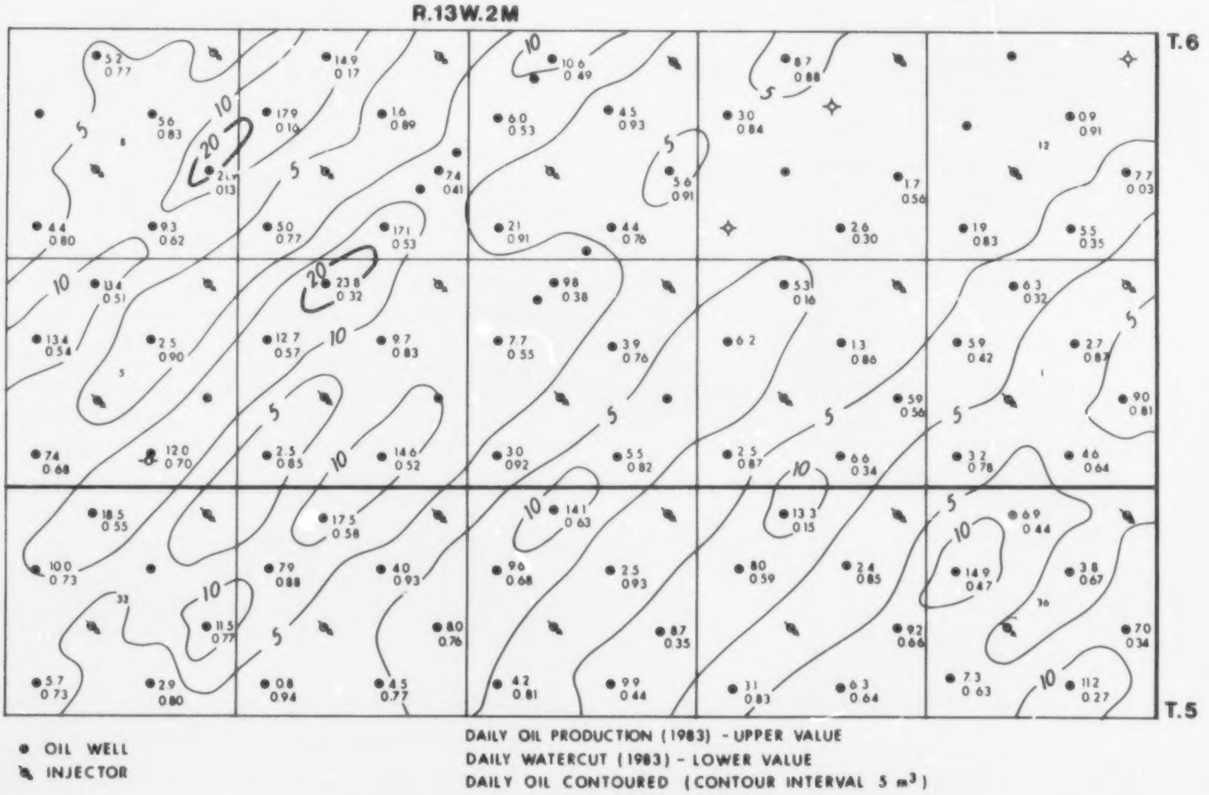
R.13W.2M
T.6
T.5
● OIL WELL
INJECTOR
DAILY OIL PRODUCTION (1983) - UPPER VALUE
DAILY WATERCUT (1983) - LOWER VALUE
DAILY OIL CONTOURED (CONTOUR INTERVAL 5 m³)

Fig. 11 - Contoured production data show a preferential northeast-southwest orientation; see text for explanation.

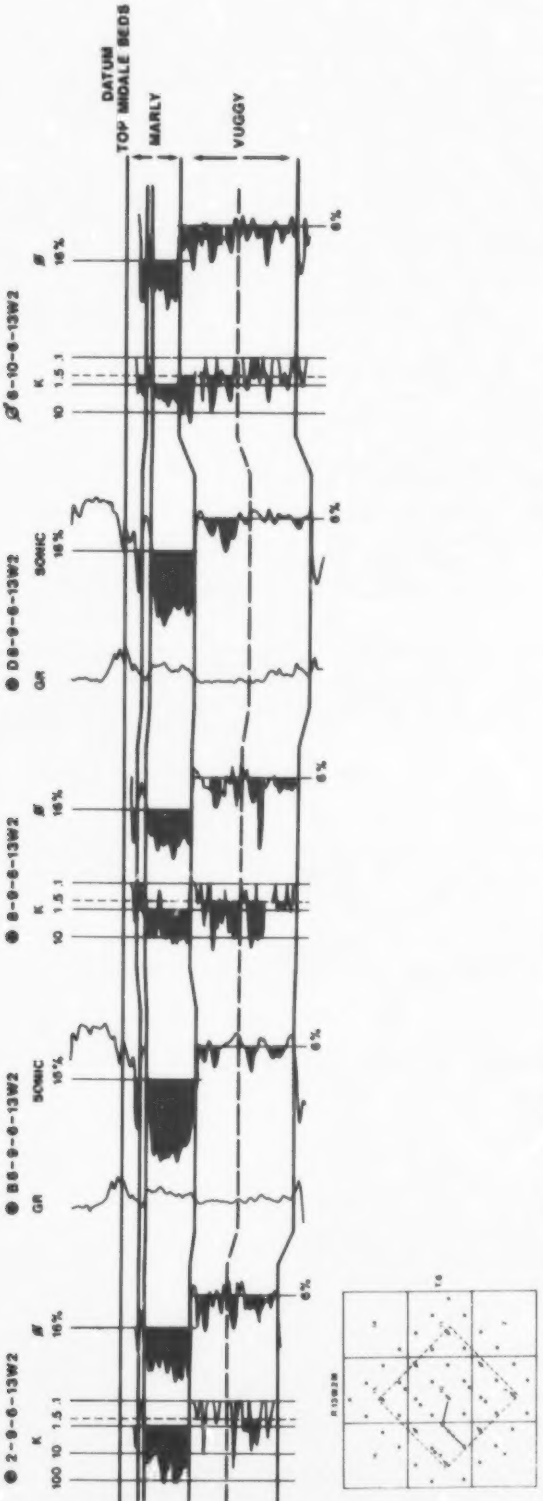

Fig. 12 - "Pattern 91" infill project location and cross section showing reservoir heterogeneity.

Workover programs are important, because many wellbores are presently not in optimal condition. Communication between zones due to bad cement bond is a common problem in the Weyburn Unit, often resulting in water channelling along production casing. A 1983 workover program conducted on four wells (Table 2) was encouraging. Selective perforation and acidization by using a selective injection packer tool (60 cm spacing) resulted in proper completion of less permeable but potentially productive zones that were initially bypassed.

"Pattern 91" infill locations:	**Workover program locations:**
B14-03-06-13 W2M	08-35-05-13 W2M
B08-09-06-13 W2M	12-35-05-13 W2M
D08-09-06-13 W2M	02-01-06-13 W2M
B02-10-06-13 W2M	12-01-06-13 W2M
B14-10-06-13 W2M	
B02-15-06-13 W2M	

Table 2 - Well locations for infill drilling and workover programs.

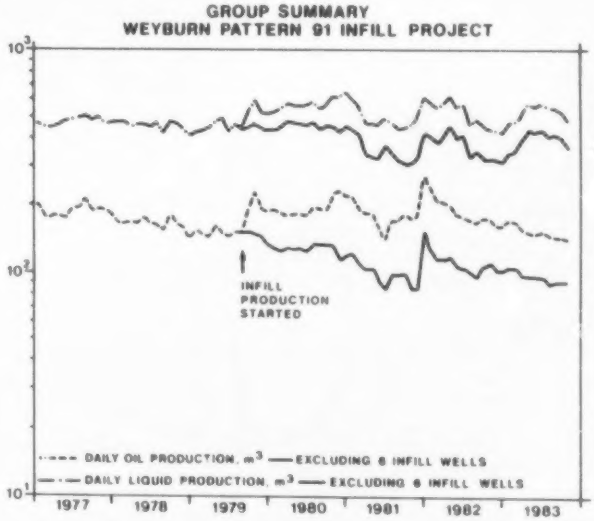

Fig. 13 - Production history plot for "Pattern 91" infill project.

SUMMARY AND CONCLUSIONS

The Midale Beds in the Weyburn form a complex reservoir. Contrasts in pore types between the "Marly" and "Vuggy" units cause different reservoir response with regard to completion and production. Porosity development in the Midale Beds is the result of diagenesis more than depositional environment, as illustrated by the dolomite of the "Marly" reservoir. Correlation of individual porous zones in the "Vuggy" unit is difficult. The intricate distribution of porosity and permeability reduces waterflood efficiency. Random distribution of anhydrite and/or calcite occludes porosity. An apparently pressure sensitive northeast-southwest trending joint system provides distinctly preferential fluid migration paths, generally independant of reservoir porosity and permeability distribution.

With approximately 75% of original oil in place still remaining in the reservoir, the Weyburn Field and comparable fields in southeast Saskatchewan form attractive challenges. Recovery efficiency can be improved by workover programs of existing wells with selective perforation and stimulation of "next best zones". Additional reserves can be recovered through infill drilling on a reduced spacing area. Detailed reservoir sensitivity studies and pilot projects are required to determine the viability and best method of enhanced recovery schemes yet to be implemented.

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DEPOSITIONAL PATTERNS AND OIL FIELD TRENDS IN THE LOWER MESOZOIC OF THE NORTHERN WILLISTON BASIN, CANADA

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ABSTRACT

The Early Mesozoic depositional setting of the Williston Basin went through several phases following termination of the vast Paleozoic marine systems by the epeirogeny following the Appalachian orogeny. Severe contraction of the Basin occurred in the Triassic, as indicated by the distribution of the upper Spearfish-Lower Watrous and the Amaranth red-beds and evaporites. At that time, the basin was made up of two trapezoidal troughs: one trended northwest into Saskatchewan from an intersection in North Dakota with the other, which extended northeast form Wyoming to southwestern Manitoba (The Amaranth sub-basin). Structural blocks flanking this Triassic basin exercised shore-margin controls on sedimentation formats of the succeeding marine Jurassic basins.

Onshore flats dominated the Triassic depositional floor of continental to marine red-bed clastics and evaporites. These were succeeded by Middle Jurassic deeper water sedimentation, that progressed from sabkha-like bodies to off shore marine, as seen in the Upper Watrous, Gravelbourg, and Shaunavon Formations (Piper Group). Maximum expansion of the basin occurred during the Rierdon and Swift episodes of deposition; this was accompanied by uplifts of the Sweetgrass Arch, the Swift Current Platform and the Punnichy Arch along the northwestern and northern rims of the basin. Swift sedimentation was ended by progradation of continental sediments from central Saskatchewan and Manitoba in the north (Success Formation) and from Wyoming in the south (Morrison Formation).

The Jurassic and Jura-Cretaceous strata of southwestern Saskatchewan and the Triassic of southwestern Manitoba are major petroleum producing regions. The former comprises isolated shoreline sand bodies in the Shaunavon Formation and unconformity-bounded mesas, buttes and promontories in the Roseray and Success Formations. The Triassic reservoirs are permeable sand bodies in otherwise low-permeability sandy mudstones.

INTRODUCTION

The strata reviewed in this paper include the Triassic lower Watrous-Upper Spearfish beds, the Middle Jurassic Piper Group comprising the upper Watrous, Gravelbourg and Shaunavon Formations, the Upper Jurassic Vanguard Group and the Jura-Cretaceous Success Formation.

These formations crop out in the uplifts of Central Montana; in Saskatchewan they lie at depths ranging from 3,000 to 5,000 ft. Petroleum reservoirs in the Williston Basin are largely restricted to the Middle Jurassic and younger strata. However, the Triassic Amaranth (Watrous) red beds came into production in 1980 with the development of the Waskada oil field in Manitoba (Barchyn, this volume). This discovery followed some smaller finds in North Dakota.

Excellent regional studies and reviews of the Jurassic of the Williston basin region are in existence. These include the prioneering works of Imlay (1945, 1947), Imlay *et al.* (1948), Cobban (1945), Francis (1956, 1957), Milner and Thomas (1954), Milner and Blakslee (1958), Nordquist (1955), Peterson (1957), Thompson and Crockford (1958), Springer, MacDonald and Crockford (1964), Carlson (1968) and more recently by Peterson (1972), Imlay (1980) and Poulton (in press).

Thus the scope of this paper is limited to presentation of thumb-nail sketches of the Lower Mesozoic strata in the region (primarily Saskatchewan), and the relation of depositional patterns to the major oil field trends of southwestern Saskatchewan. In this it draws heavily upon earlier works by the author.

THE PRE-MESOZOIC BASIN

The Williston Basin assumed several configurations from the Late Paleozoic to the Early Cretaceous, although its depositional centre remained near the International boundary in western North Dakota and northeastern Montana. Overall, it spread over a large quadrilateral region with flanks that trended northwest and northeast (Fig. 1). In the southwest subsidiary basins or troughs extended westward at different times across central Montana and south into Wyoming. Enlargement and contraction of the basin area apparently reflected not only relative rise and fall of sea level, but also vertical movements of local structural blocks or regions. The most significant of these were the Central Montana Platform -Sweetgrass Arch complex in the west and the Punnichy Arch forming the basin rim to the north and northeast in southern Saskatchewan. Although the Late Paleozoic basin was restricted to this region of Saskatchewan, earlier in the Middle Devonian it was linked with the Elk Point Basin that extended northwest across Alberta into the Northwest Territories. Pre-Mesozoic erosion has stripped back the edges of the formations so that subcrops young centripetally. In Saskatchewan this younging is to the south (Fig. 2).

The erosional edge of the Early Mississipian (Kinderhookian to Early Meramecian) forms the most southerly outcrop of the transgressive Paleozoic carbonate beds (Fig. 3). The broadly spaced isopach contours between 0 and 1000 ft represent these limestones where they conform to the wide low relief platform and arches flanking the west-southwesterly trough of the Williston Basin to the north and to the south. The younger Meramecian and Chesterian strata more nearly approximate shore environments, being largely supratidal dolomitic and evaporitic sequences. The sequence is regressive and represents a progressive shrinkage of the depositional basin; thus its presence within the confines of the curved 1,000 ft contours of Figure 3 is only partly a function of post-Mississippian, pre-Triassic erosion. The isopach contours of the Mississippian strata more nearly approximate in shape the classical circular forms of the Williston basin over the eastern area of their distribution. However, to the west (central Montana), the contours delineate an elongate trough extending west-southwest.

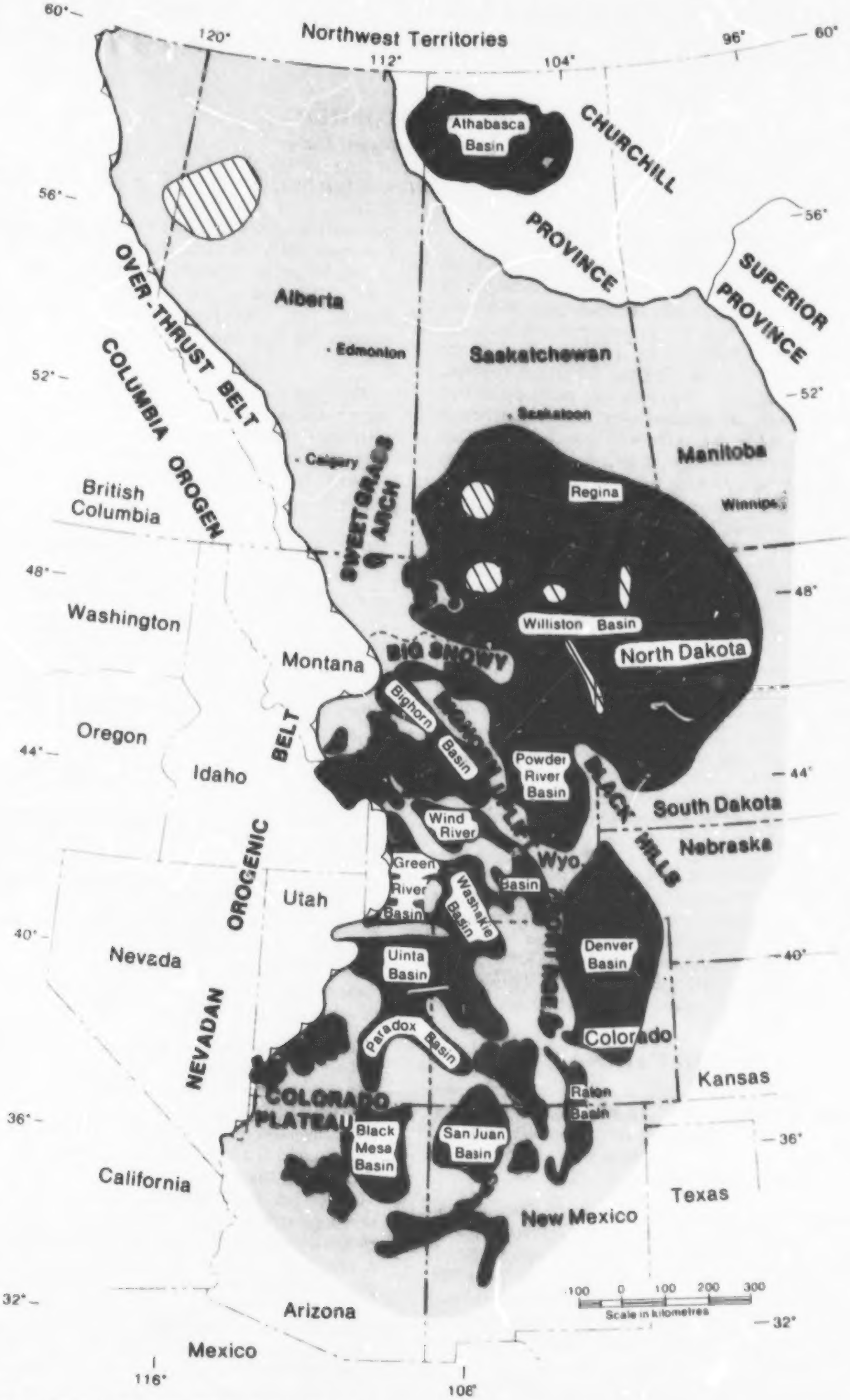
60°
120°
Northwest Territories
112°
104°
96°
60°
Athabasca Basin
CHURCHILL PROVINCE
56°
56°
SUPERIOR PROVINCE
OVER-THRUST BELT
Alberta
Edmonton
Saskatchewan
52°
52°
COLUMBIA OROGEN
Saskatoon
Manitoba
Calgary
SWEETGRASS ARCH
Regina
Winnipeg
British Columbia
48°
48°
Washington
Williston Basin
North Dakota
BIG SNOWY
Montana
Bighorn Basin
BIGHORN UPLIFT
Oregon
BELT
Powder River Basin
44°
44°
Idaho
BLACK HILLS
South Dakota
Wind River
Nebraska
OROGENIC
Green River Basin
Washakie Basin
Wyo.
Basin
Utah
FRONT RANGE
40°
40°
Nevada
Denver Basin
Uinta Basin
NEVADAN
Colorado
Paradox Basin
Kansas
COLORADO PLATEAU
Raton Basin
36°
36°
Black Mesa Basin
San Juan Basin
California
Texas
New Mexico
100 0 100 200 300
Scale in kilometres
32°
32°
Arizona
Mexico
116°
108°

Fig. 1 - Regional setting of the Williston Basin in the Western Interior of North America.

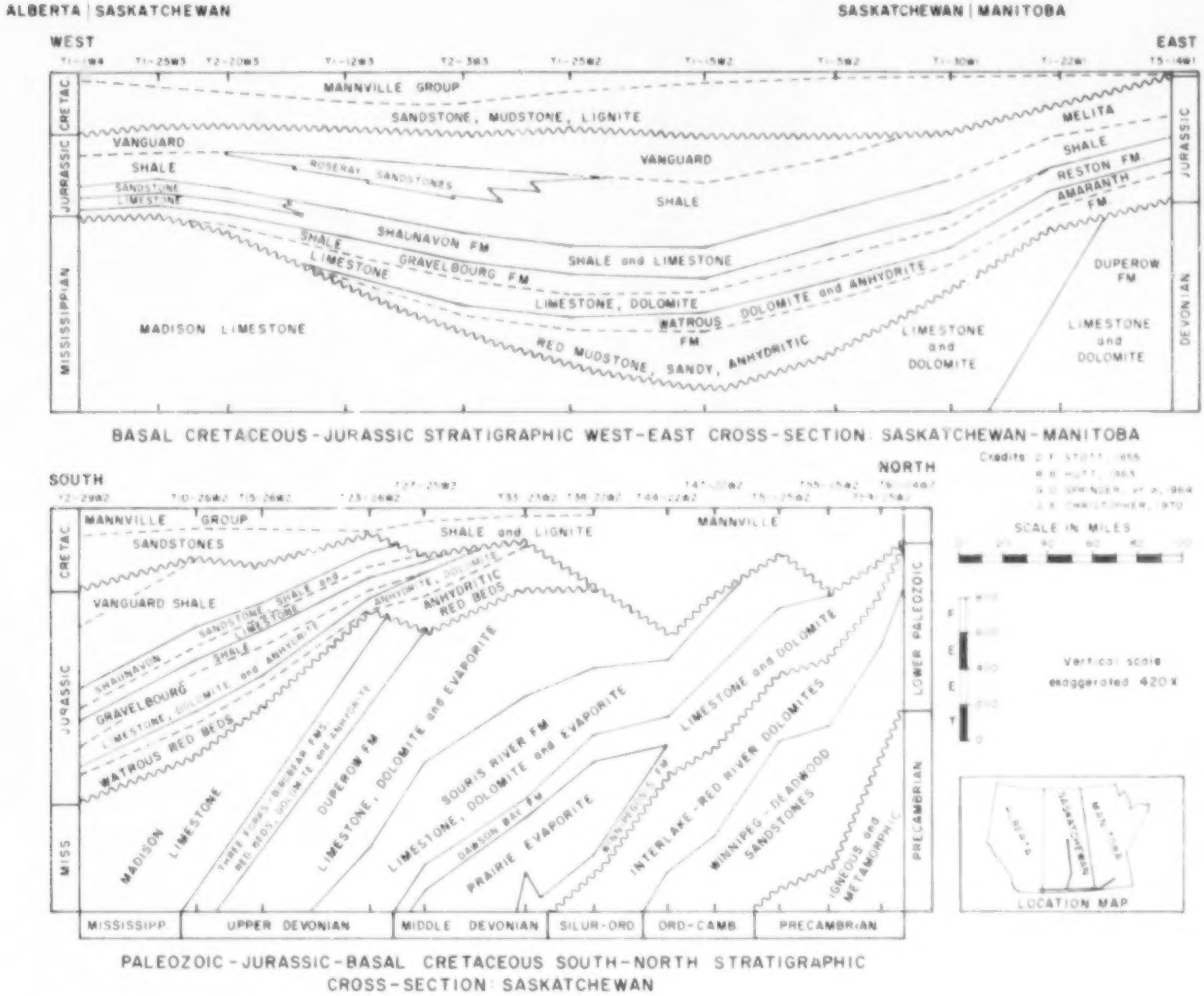
ALBERTA | SASKATCHEWAN
SASKATCHEWAN | MANITOBA
WEST
EAST
CRETAC
JURASSIC
MISSISSIPPIAN
DEVONIAN
MANNVILLE GROUP
SANDSTONE, MUDSTONE, LIGNITE
VANGUARD
SHALE
SANDSTONE
LIMESTONE
ROSERAY SANDSTONES
VANGUARD
SHALE
MELITA
SHALE
RESTON FM
AMARANTH FM
SHAUNAVON FM
SHALE
LIMESTONE
GRAVELBOURG FM
SHALE and LIMESTONE
LIMESTONE, DOLOMITE
DOLOMITE and ANHYDRITE
WATROUS FM
RED MUDSTONE, SANDY, ANHYDRITIC
MADISON LIMESTONE
LIMESTONE and DOLOMITE
DUPEROW FM
LIMESTONE and DOLOMITE
BASAL CRETACEOUS-JURASSIC STRATIGRAPHIC WEST-EAST CROSS-SECTION: SASKATCHEWAN-MANITOBA
SOUTH
NORTH
Credits
SCALE IN MILES
MANNVILLE GROUP
SANDSTONES
SHALE and LIGNITE
MANNVILLE
VANGUARD SHALE
SANDSTONE, SHALE and LIMESTONE
SHAUNAVON
SHALE
GRAVELBOURG
LIMESTONE, DOLOMITE and ANHYDRITE
WATROUS RED BEDS
ANHYDRITE, DOLOMITE
ANHYDRITIC RED BEDS
MADISON LIMESTONE
THREE FORKS - BIRDBEAR FMS. RED BEDS, DOLOMITE and ANHYDRITE
DUPEROW FM
LIMESTONE, DOLOMITE and EVAPORITE
SOURIS RIVER FM LIMESTONE, DOLOMITE and EVAPORITE
DAWSON BAY FM
PRAIRIE EVAPORITE
WINNIPEGOSIS FM
LIMESTONE and DOLOMITE
INTERLAKE-RED RIVER DOLOMITES
WINNIPEG-DEADWOOD SANDSTONES
IGNEOUS and METAMORPHIC
LOWER PALEOZOIC
PRECAMBRIAN
MISS
MISSISSIPP.
UPPER DEVONIAN
MIDDLE DEVONIAN
SILUR-ORD
ORD-CAMB
PRECAMBRIAN
Vertical scale exaggerated 420 X
LOCATION MAP
PALEOZOIC-JURASSIC-BASAL CRETACEOUS SOUTH-NORTH STRATIGRAPHIC CROSS-SECTION: SASKATCHEWAN

Fig. 2 - Cross section of the Lower Mesozoic a) west-east (Saskatchewan-Manitoba); b) south-north (Saskatchewan).

In Saskatchewan and Manitoba the Triassic Watrous and Amaranth red beds lie unconformably on the Mississippian carbonates. In North Dakota and Montana, the hiatus is partly represented by some 1,500 ft of late Mississippian, Pennsylvanian and Permian strata. These comprise evaporitic salts and carbonates with black shales and channelled sandstones and red beds; the series are bounded by unconformities (Mallory, 1972; Roscoe and Baars, 1972). The isopach patterns for these formations show a rotation of the depositional axis to the southwest, with Mississippian (Madision) carbonates in the central Montana region forming part of an enlarged upland or structural platform (Fig. 3).

TRIASSIC WATROUS - SPEARFISH BASIN

The Watrous formation was named after the town of Watrous in southern Saskatchewan by Milner and Thomas (1954); the type section is in Davidson Crown No. 1 (16-8-27-1W3). The Formation is synonymous with Stott's (1955) Amaranth Formation of Manitoba. In common usage, the unit is divided into an upper member dominated by anhydrite and dolomite and a lower member characterized by red beds of dolomitic and anhydritic mudstones and shales with minor lenses of quartzose sandstone. Because of the lack of diagnostic fossils, disagreement exists as to whether or nor the lower member is Jurassic. The outward and upward expansion of marine facies in the overlying Jurassic section, suggests that the lower Watrous is the beginning of the Jurassic transgression (Barchyn, 1982; this volume). On the basis of regional correlation, however, it is considered to be an extension northward of the Spearfish Formation of North Dakota (Francis, 1956), which is designated Triassic. In this paper the lower Watrous is taken as the equivalent of the upper Spearfish as mapped by MacLachlan (1972).

The Spearfish Formation of the Williston Basin is a bipartite Permo-Triassic unit (MacLachlan, 1972). As delineated in cross-section by Roscoe and Baars (1972) the upper Spearfish, which is floored by the Pine Salt, truncates the Permian lower Spearfish northward toward Saskatchewan. This truncation continues across the Pennsylvanian and the Upper Mississippian into Saskatchewan, where the uncomformity underlies

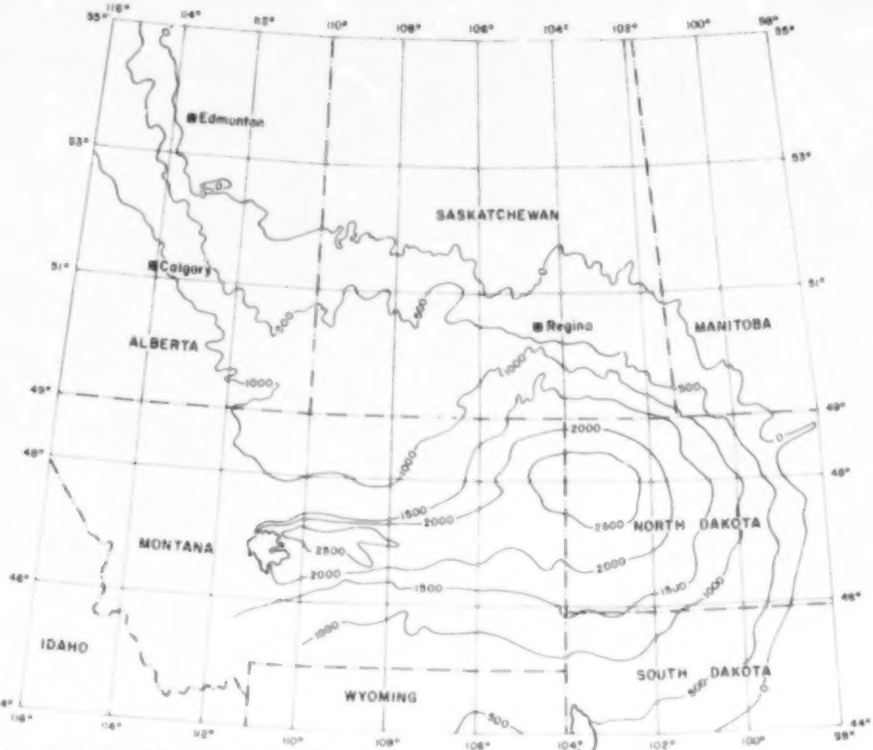
Edmonton
Calgary
Regina
SASKATCHEWAN
MANITOBA
ALBERTA
MONTANA
NORTH DAKOTA
SOUTH DAKOTA
IDAHO
WYOMING
500
1000
1500
2000
2500
0
116°
114°
112°
110°
108°
106°
104°
102°
100°
98°
55°
53°
51°
49°
48°
46°
44°

Fig. 3 - Isopach map of the Mississippian Madison Group in the Williston Basin region (after Craig, 1972 and Macauley *et al.*, 1964)

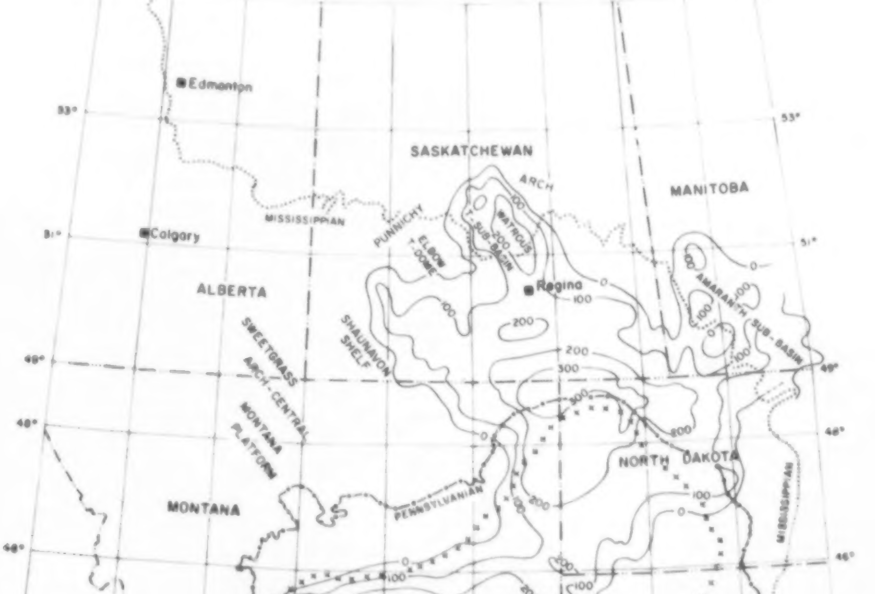
Edmonton
Calgary
Regina
SASKATCHEWAN
MANITOBA
ALBERTA
MONTANA
NORTH DAKOTA
SOUTH DAKOTA
IDAHO
WYO
ARCH
PUNNICHY
WATROUS
SUB-BASIN
ELBOW T. DOME
MISSISSIPPIAN
SHAUNAVON SHELF
SWEETGRASS ARCH-CENTRAL MONTANA PLATFORM
AMARANTH SUB-BASIN
PENNSYLVANIAN
PERMIAN
POPO AGIE
0
100
200
300
400
500
600
700
116°
114°
112°
110°
108°
106°
104°
102°
100°
98°
55°
53°
51°
49°
48°
46°
44°

Fig. 4 - Isopach map of the Triassic Spearfish and lower Watrous-Amaranth strata in the Williston Basin region (after Maclachlan, 1972 and Springer *et al.*, 1964).

the lower Watrous (Fig. 3). This correlation thus suggests an Early Triassic age for the Lower Watrous and thereby implies: 1) that an unconformity separates the lower Watrous from the upper; and 2) the existence of a hiatus spanning the Middle Triassic and Early Jurassic. Such a hiatus is indicated by the presence of the Late Triassic Alcova Limestone, Jelm and Popo Agie Formations (O-Y) in the central portion of the Triassic basin (see Fig. 4 for their northern edge in Wyoming).

The Triassic Watrous-Spearfish basin differs sharply in configuration from its predecessors. There are two main elements: 1) a northeasterly trending approximately rectangular trough extending from northern Wyoming across the centre of the structural Williston Basin to southwestern Manitoba where it forms the Amaranth embayment; and 2) a similar, but broader, form projecting from the Williston basin centre northwest into Saskatchewan. Although the lower Watrous is conventionally interpreted to infill an eroded topographic surface, the regional setting indicates an overprinted static structural control. Only south latitude 46° is high mobility indicated: there the formation thickens strongly into Wyoming. In the region to the north, isopach relief is only about 100 ft, and northeasterly and northwesterly trends predominate. These patterns are strongly characteristic of Mesozoic sedimentary and structural trends in the basin.

Permo-Triassic epeirogeny and warp of the craton were consequences of the Appalachian orogeny. This phenomenon is apparently expressed in the Williston Basin region by relative up-tilt of cratonic blocks along lineaments marginal to the axial regions of the basin. To carry the extrapolations further, the underlying structural framework of the basin well may be a weak pull-apart along the lineaments.

Subsequent erosion breached and sculptured the gently dipping Mississippian carbonates of southeastern Saskatchewan into cuestas centripetal to the basin centre (Fuzesy, 1960; Martin, 1966). Movement along the northeastern margin of the basin in Saskatchewan was accompanied by flexuring of the Punnichy Arch (Christopher, 1980, p. 20). Erosion of these flexures apparently lead to a second generation of topographic forms that were the reverse of the underlying structures. Anticlines in the Mississippian and Devonian carbonates were breached and their cores eroded to a local base level, thereby forming topographic basins infilled with Watrous sediments. Synclinal beds not eroded by virtue of their initially low topographic positions, remained topographic highs rising above the Watrous fill. This is illustrated in the cross-section of the Watrous embayment and the adjacent Elbow structural trough (Fig. 5).

A south trending ridge along longitude 102° separates the Saskatchewan portion of the Williston Basin from the Amaranth sub-basin of Manitoba. This ridge coincides with a negative gravity anomaly in the basement (McCabe, 1967) as well uplifts of Late Devonian-Early Mississippian (Christopher, 1961) and post-Mississippian-pre-Triassic age. The massive Sweetgrass Arch-Central Montana Platform complex controlled the western flank of the Lower Watrous-Spearfish basin. Floored by a thousand feet of Mississippian carbonates, the region formed a broad plateau that descended eastward across terraces of the Shaunavon shelf (Fig. 6) to the relatively flat-floored basin.

Lower Watrous sediments were mostly derived from the surrounding carbonate terrain. These sediments are largely red and green mottled dolomitic mudstones and shales,

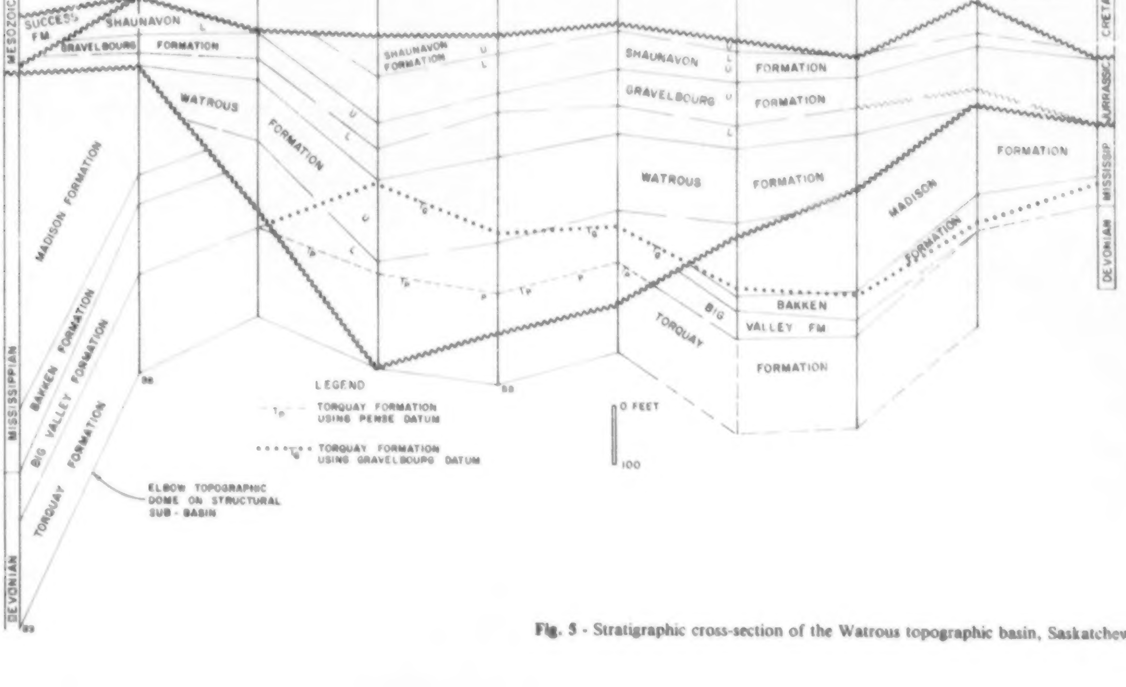
13-4-25-8W3
12-16 26-4W3
4-29-25-1W3
4-28-25-26W2
4-32-25-23W2
8-29-25-20W2
13-11-25-18W2
1-14-25-16W2
1-29-25-12W2
7-24-25-9W2
24 MILES
16
21
18
16
14
12
20
21
PENSE FORMATION
CANTUAR FORMATION
SUCCESS FM
SHAUNAVON
GRAVELBOURG FORMATION
SHAUNAVON FORMATION
U
L
WATROUS FORMATION
GRAVELBOURG FORMATION
MADISON FORMATION
BAKKEN FORMATION
BIG VALLEY FORMATION
TORQUAY FORMATION
BAKKEN
BIG VALLEY FM
TORQUAY FORMATION
MADISON FORMATION
FORMATION
Tp
Tg
P
MESOZOIC
MISSISSIPPIAN
DEVONIAN
CRETACEOUS
JURASSIC
MISSISSIP
DEVONIAN
LEGEND
Tp TORQUAY FORMATION USING PENSE DATUM
Tg TORQUAY FORMATION USING GRAVELBOURG DATUM
0 FEET
100
ELBOW TOPOGRAPHIC DOME ON STRUCTURAL SUB-BASIN
BB

Fig. 5 - Stratigraphic cross-section of the Watrous topographic basin, Saskatchewan.

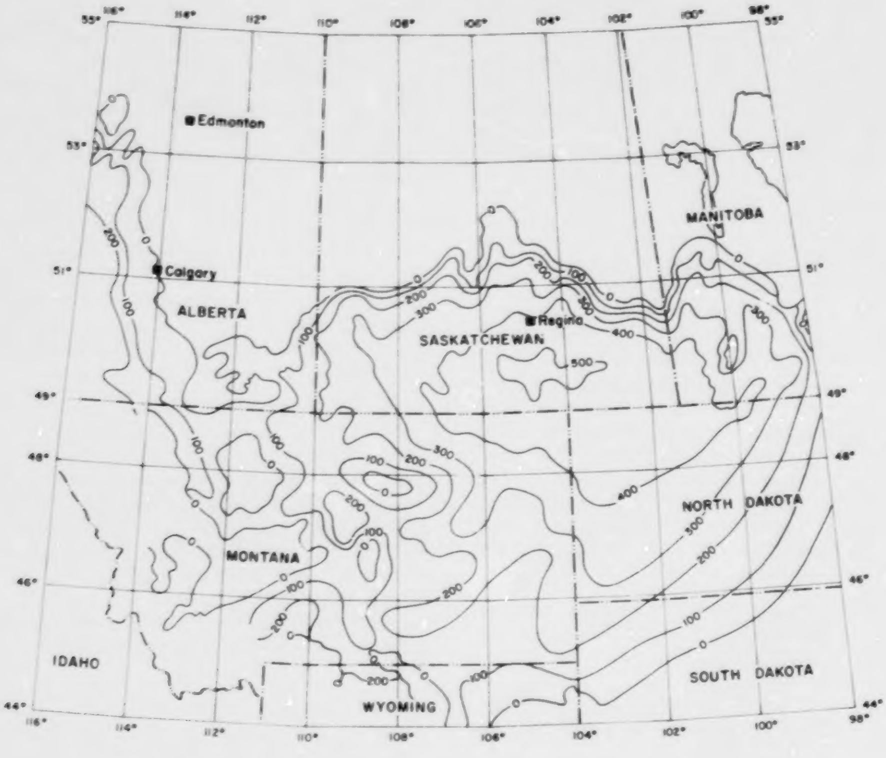

Fig 6 - Isopach map of the Middle Jurassic strata in the Williston basin (after Peterson, 1972 and Springer *et al.*, 1964).

argillaceous quartzose siltstones and minor sandstones, which are interrupted near the top by thin layers, blebs, patches and veinlets of white anhydrite. Beds of quartzose fine and medium sandstone from a minor component in the east and southeast, especially in the Amaranth sub-basin (Barchyn, 1982; this volume) and surrounding areas in southeastern Saskatchewan and eastern North Dakota (Francis, 1956, p. 21). Floating frosted quartz grains occur throughout.

Regionally persistent markers are generally recognised in geophysical log cross sections of the lower Watrous. This is a common characteristic of formations deposited under marine influences. Canadian authors have generally recognized the Watrous as the beginning of the Middle Jurassic marine succession, although few would uncategorically attribute it to a marine or continental depositional environment (*cf.* Klingspor, 1958). The evidence is ambiguous. Barchyn (1982; this volume) proposes fluviatile-onshore depositional espisodes on a flat mud plain with intervening marine flooding and reworking of the continental deposits in an arid to semi-arid climate. The writer agrees. In this context, subaerial exposure of large regional flats during regressions would contribute to widespread formation of red beds. This process would be supplemented by introduction of terra rosa from the uplands in episodic flash floods. Another source of ferric iron would be reduced muds of supratidal algae mats, indicated by the presence of anhydrite and salt beds farther south in the Williston Basin. Some of these salt beds, including dolomite, may have extended north into Saskatchewan; if so, they were dissolved during the prolonged period of exposure preceeding deposition of the Middle Jurassic sediments.

MIDDLE JURASSIC PIPER BASIN

The Piper Formation was defined by Imlay *et al.* (1948) "to include all the Middle Jurassic red-beds, gypsum and associated normal marine beds underlying the Rierdon Formation in eastern Montana east of the Sweetgrass-Big Belt line of uplift. . . It is named after Piper about 11 miles southeast of Lewistown, Montana. . . The type section from base to top consists of about 12 feet of massive white gypsum, 6 feet of chocolate grey limestone, 57 feet of maroon and green siltstone and shale, 5 feet of grey, silty limestone, 9 feet of gray papery to chunky shale, and 4 feet of yellowish gray sandy limestone". West of the Sweetgrass-Big Belt line, the Piper loses much of its evaporitic-red bed character as it grades into the sandstone gray shale facies of the Sawtooth Formation, which is characterized by a more open marine fauna. In Saskatchewan the Piper is represented by the upper member of the Watrous Formation, as well as the Gravelbourg and Shaunavon Formations as defined by Milner and Thomas (1954).

The Piper depositional basin resembles the Spearfish basin in the retention of northeasterly and northwesterly trends, but it lacks the former precision of outline (Fig. 6). It is apparent that Piper sediments have broadly encroached upon the Sweetgrass Central Montana Platform complex in the west and the outlying basin flank to the southeast in Dakotas. This expansion of the depositional basin reflects the transgressive nature of the sedimentary sequence in vertical section. This is reflected by a transition from the restricted basin evaporites of

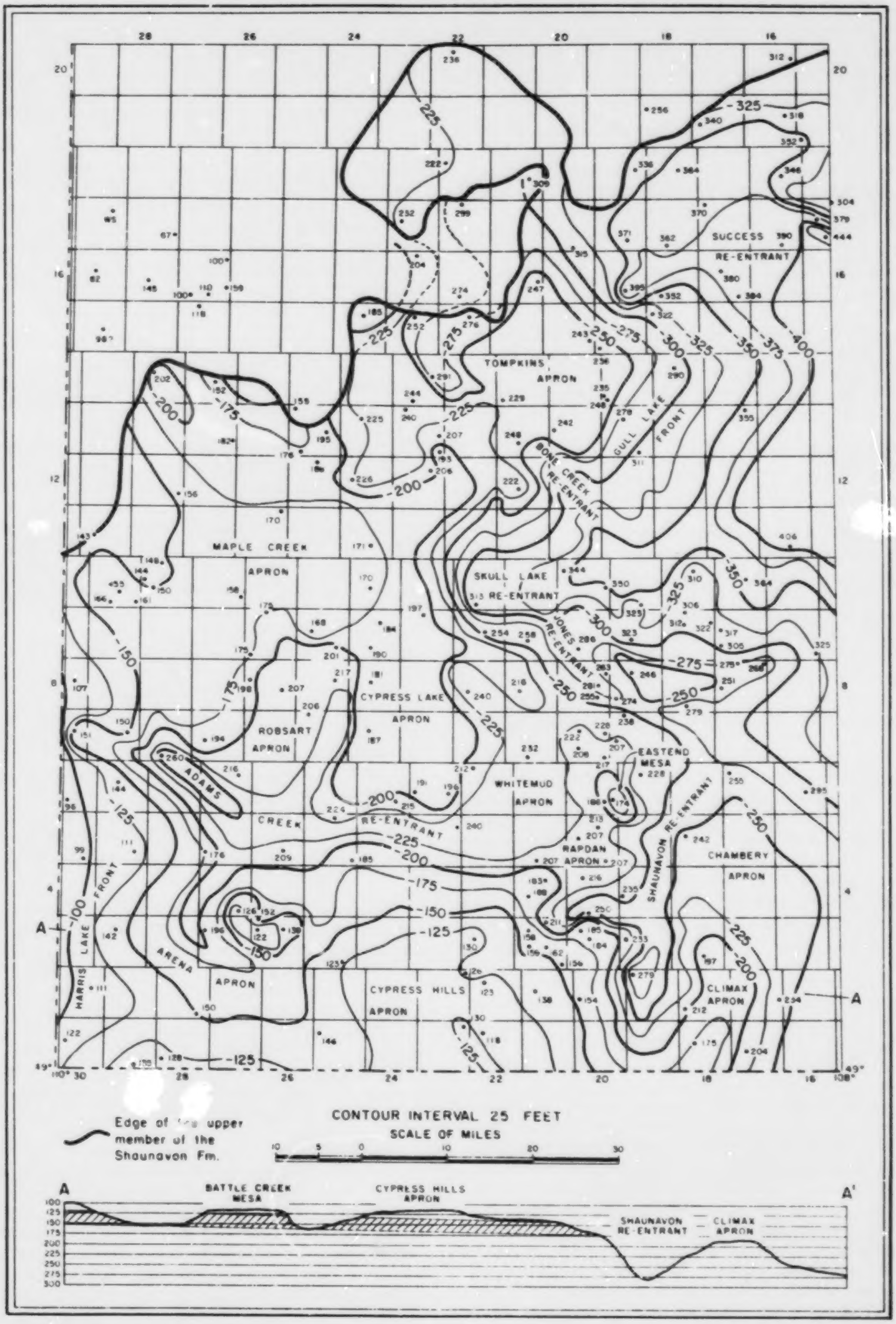
28
26
24
22
20
18
16
20
16
12
8
4
49°
110° 30
108°
TOMPKINS APRON
GULL LAKE FRONT
BONE CREEK RE-ENTRANT
SUCCESS RE-ENTRANT
MAPLE CREEK APRON
SKULL LAKE RE-ENTRANT
JONES RE-ENTRANT
CYPRESS LAKE APRON
ROBSART APRON
ADAMS CREEK RE-ENTRANT
WHITEMUD APRON
EASTEND MESA
RAPDAN APRON
SHAUNAVON RE-ENTRANT
CHAMBERY APRON
HARRIS LAKE FRONT
ARENA APRON
CYPRESS HILLS APRON
CLIMAX APRON
A
A
-100
-125
-150
-175
-200
-225
-250
-275
-300
-325
-350
-375
-400
Edge of the upper member of the Shaunavon Fm.
CONTOUR INTERVAL 25 FEET
SCALE OF MILES
10 5 0 10 20 30
A
A'
BATTLE CREEK MESA
CYPRESS HILLS APRON
SHAUNAVON RE-ENTRANT
CLIMAX APRON
100
125
150
175
200
225
250
275
300

Fig. 7 - Isopach map of the Watrous and Gravelbourg Formations in southwestern Saskatchewan. Section A-A' is across inferred topography (after Christopher, 1964).

the upper Watrous to the deeper and more open marine dark green fossilifeous shales and buff limestones of the Gravelbourg and Shauanvon Formations. The depositional center apparently shifted to southern Saskatchewan, where the sequence attains a thickness of some 500 ft.

The basin apparently extended as far north as latitude 52°, *i.e.*, beyond the closely spaced contours at the northern edge in Fig. 6, which are a result of Late Jurassic erosion. In contrast, the relatively broad, irregular distribution of contours in the west and southwest portrays draping and partial infill of the pre-Watrous upland. This occurred by net depositional onlap. Near the centre, the basin was largely flat-floored as a result of Lower Watrous infilling. This low relief accounts for the persistence of marker beds across the basin.

The Upper Watrous Member is dominated by white, coarsely crystalline anhydrite, which is partially by stringer and beds of gypsum near the northern erosional edge and in the Amaranth embayment where they attain a thickness of 25 ft. Subordinate variegated shale up to 20 ft thick may be interbedded with anhydrite, and pockets of dolomite are found locally. Southward into North Dakota, the anhydrite yields increasingly to the dolomites and variegated shale. Thickness of the member is of the order of 100 ft.

The Gravelbourg Formation consists of limestone, dolomitic limestone, calcareous shales and sandstones. Two members are generally recognized: the lower is carbonate-rich; and the upper is argillaceous with quartzose sand. This dichotomy is recognized in Manitoba by designation of the lower member as the Reston Formation, and the upper as the basal portion of the Melita Formation (Scott, 1955). In North Dakota and Montana the corresponding units are the Kline Member of the Nesson Formation (which also includes the upper Watrous) and the Picard Shale (Nordquist, 1955).

In the type area in southwestern Saskatchewan, the lower member constitutes 7 ft of dark green dolomitic shale with abundant fish scales, overlain by 35 ft of tan, dolomitic limestone with thin partings of green shale. Chalcedonic chert, infilling and replacing partings, is common in shales in the lower 22 ft. Oolitic limestone with glauconite and alga forms is common. Eastward in southeastern Saskatchewan and southward into North Dakota, the upper limestone grades into dolomitic limestone with an accompanying increase in chert (Francis, 1957).

Calcareous, greenish grey shale interbedded with subordinate limestone in southwestern Saskatchewan and sandstone in the southeast characterize the upper member. The sandy facies occur in the upper half of the member, overlying a hidden unconformity which becomes pronounced near longitude 102°. Channel sandstones featuring brownish grey to white, coarse to medium grained, poorly sorted, sideritic, quartzose sands occur sporadically as far west as longitude 105°. Channels tend to truncate the underlying units of the member. At the arch along longitude 102°, even the lower member of the Gravelbourg has been removed by channel incision, such that the upper unit directly overlies the Watrous Formation. Compared to the relatively uniform thickness (80 ft or so) of the lower member, thickness of the upper member increases eastward and ranges up to 150 ft. Although several diastemic breaks represented by vertically burrowed calcilutite layers mark the contact zone between the Gravelbourg and Shaunavon Formations, this contact is considered to be transitional by virtue of interbedding of the shale and calcilutite.

In the west the Gravelbourg completely onlaps the eastern flank of the Sweetgrass Arch; *i.e.*, the so-called Shaunavon shelf of Saskatchewan. The topography of this shelf, which is mirrored by the combined isopachs of the Watrous and Gravelbourg Formations (Fig. 7), exerted a pronounced control on the distribution of facies in the Shaunavon Formation.

The Shaunavon Formation is also bipartite. The lower member is made up of a distinctive buff and tan, earthy, brittle calcilutite that resembles a lithographic limestone with a restricted fauna characterised by an abundance of large pelecypods, solitary corals, and verti-spiralled gastropods. The upper member is dominated by fine, bedded, quartzose, sand cemented by an oolitic, dark grey-blue and tan, calcareous dolomitic matrix. Fossils are also abundant; assemblages are dominated by small pelecypods.

The buff colour, purity and consistency of lithology and thickness of the lower member are characteristic features; the member is traceable across the Williston Basin as far east as longitude 104°. Farther east, the member is indentifiable on geophysical logs, even as it grades into green-grey calcareous shale and argillaceous, quartzose sandstone. The sandstones feather out westward from Manitoba and southward off the Punnichy arch (Fig. 4). As in the upper Gravelbourg, the regional sandstones are dissected by channel sandstones up to 70 ft thick. The subsurface calcilutite crops out in the Bearpaw uplift of northern Montana as a dark grey, dense, microcrystalline limestone, hydrothermally altered by an intrusive. The general lithological uniformity of the lower Shaunavon member makes it the pre-eminent seismic reflector in the Mesozoic. Locally, especially on the Shaunavon shelf, the member is distinctly oolitic in the upper 25 ft; it is also dolomitized in an area of lesser extent. Dolomitization has transformed the earthy calcilutite into a dark brown, dense, microcrystalline rock pocked with molds of gastropods, pelecypods and ooids. In so far as post-lithification dolomitization is not observed in the upper member, it can be concluded that the age of dolomitization is pre-Upper Shaunavon and that the contact between the members represents a hiatus. Other evidence for this conclusion includes erosional truncation of the oolitic bed, as well as erosional and solution relief and conglomerates on the upper contact (Christopher, 1964, Fig. 9).

The upper member of the Shaunavon Formation in the region of the Shaunavon shelf of southwestern Saskatchewan and northern Montana constitutes very fine to fine grained quartzose sandstone, quartz cored oolitic limestone, biofragmental calcarenite and calcirudite, argillaceous limestone, and dolomite, sandstone, marlstone and shale. Calcareous sandstones predominate on the higher elevations of the shelf, i.e., the aprons (Cypress Lake, Maple Creek, Cypress Hills) above the 200 ft contour of Fig. 7. These interdigitate with the more argillaceous components eastward across the lower lying aprons.

Stratigraphically, the member consists of tabular to lenticular beds separated by sedimentation breaks ranging from diastems to true hiatuses, with dolomite weathered horizons and channels eroded through underlying units to depths of 70 ft. It is possible to trace several of the beds over broad areas by use of these discontinuities and index algal and dolomite horizons. Three units (U1, U2 and U3, bottom to top) constitute the member (Fig. 8).

The basal unit (U1) is characterized by very fine grained sandstone cemented with calcite, sandy limestone, dense

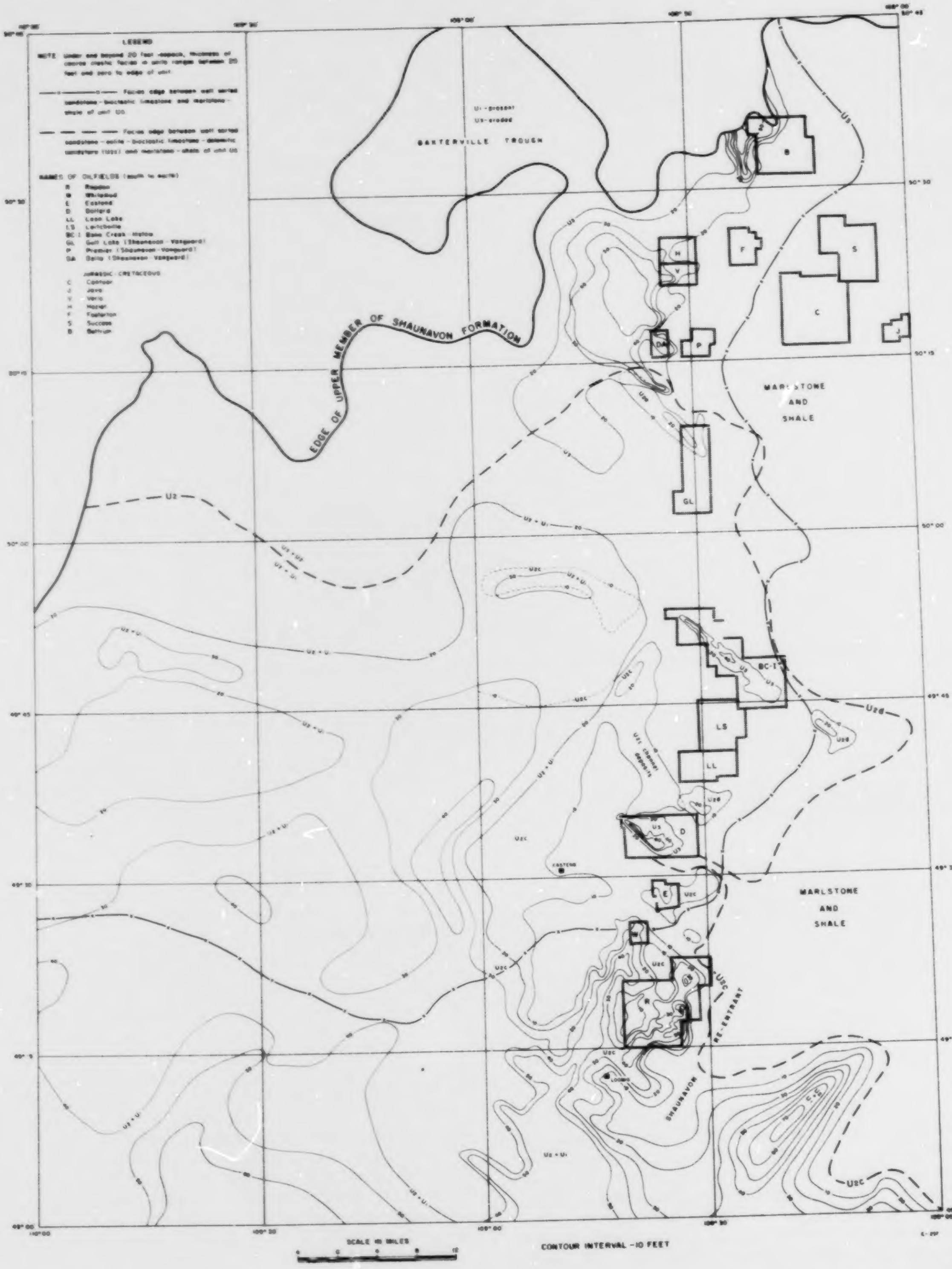
LEGEND
NOTE: Under and beyond 20 foot isopach, thickness of coarse clastic facies in units ranges between 20 feet and zero to edge of unit.
Facies edge between well sorted sandstone - bioclastic limestone and marlstone - shale of unit U3
Facies edge between well sorted sandstone - oolite - bioclastic limestone - dolomitic sandstone (U2c) and marlstone - shale of unit U2
NAMES OF OILFIELDS (south to north)
R Rapdan
W Whitmud
E Eastend
D Dollard
LL Leon Lake
LS Leitchville
BC-I Bone Creek - Instow
GL Gull Lake (Shaunavon - Vanguard)
P Premier (Shaunavon - Vanguard)
DA Delta (Shaunavon - Vanguard)
JURASSIC - CRETACEOUS
C Cantuar
J Java
V Verlo
H Hazlet
F Fosterton
S Success
B Battrum
U1 - present
U3 - eroded
BAKERVILLE TROUGH
EDGE OF UPPER MEMBER OF SHAUNAVON FORMATION
MARLSTONE AND SHALE
MARLSTONE AND SHALE
SHAUNAVON RE-ENTRANT
U2 channel deposit
U3
U2
U2c
U2d
U2 + U1
U3 + U1
EASTEND
LOOMIS
SCALE IN MILES
0 2 4 6 8 10 12
CONTOUR INTERVAL - 10 FEET
50° 45
50° 30
50° 15
50° 00
49° 45
49° 30
49° 15
49° 00
110° 00
109° 30
109° 00
108° 30
108° 00

Fig. 8 - Isopach map of Units U1, U2 and U3 of the upper member of the Shaunavon Formation in southwestern Saskatchewan (after Christopher, 1966).

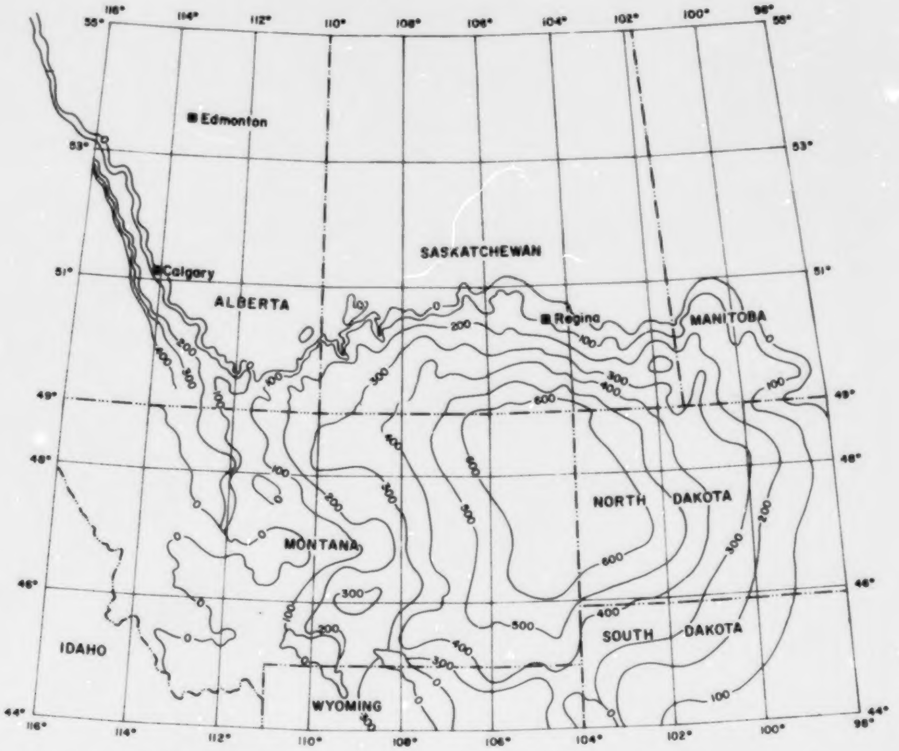

Fig. 9 - Isopach map of the Upper Jurassic in the Williston basin region (after Peterson, 1972 and Springer *et al.*, 1964).

bioclastic and microcrystalline limestone, abundant finely disseminated pyrite, dark grey-blue colour and grey-black shale. Its bedding habit ranges from massive to laminated to entirely fissile where dominated by shale. U1 is the most variable of the three units; the general resemblance of individual beds to one another renders regional intra-unit correlation uncertain.

The middle unit (U2) is thickest and most differentiated in the southeastern part of the Shaunavon shelf. The unit is best suited to regional correlation because of the presence of an algal marlstone near the top (U2d), a widespread sandy dolomitic bed underlying the algal marlstone (U2c) and a disconformable contact on unit U1 in vicinity of the Rapdan and Whitemud oil fields. In the region to the north and west this contact is considered to be above a tan, dolomitic bed at the top of Unit 1. Southward into Montana, unit U2 becomes the whole upper Shaunavon in the Bowes Oil Field and in outcrops of the Bearpaw Mountains.

Unit U3 attains its maximum thickness as sandy bioclastic calcirudite beach deposits and channel fills in the Dollard and Bone Creek-Instow Fields and as calcareous and argillaceous sandstone deposits north and northwest of the Gull Lake Field. Between the Bone Creek-Instow and Dollard Fields, widespread interfingering beds of grey-green marlstone, grey-black very argillaceous sandstone and sandy mudstone, dark and medium grey, well cemented calciruditic and sandy limestones characterize the unit. Friable sandstone predominates updip, whereas south of latitude 49° 30' and east of the oil field trend the unit grades into marlstone and shale (Fig. 8).

Eastward from the Shaunavon shelf the Upper Shaunavon facies are largely calcareous shale and marlstones. However, along the northern rim of the basin these are incised by short ranging channel sandstones extending south from the subcrop. East of latitude 102°, there is little to distinguish the member from the argillaceous and sandy Lower member.

The Piper basin reflects sedimentation interrupted by minor regressions and episodes of non-deposition and even subaerial exposure. Increased water depths are indicated by the transition of Upper Watrous supratidal evaporites to lower Gravelbourg dolomitic limestones and to upper Gravelbourg calcareous and fossiliferous shales. This was accompanied by an influx of oxygenated marine waters and the appearance of reducing bottom conditions. The influx apparently was from the Rocky Mountain trough in southwestern Montana and western Wyoming as delineated by Peterson (1957). Shallowing, mild restriction and reduction of depositional gradient are indicated by the widespread, non-argillaceous calcilutite of the lower Shaunavon, and its abundant restricted fauna. Shoaling on the flanks of the Sweetgrass arch is very much in evidence. The upper Shaunavon episode of oscillatory advances and retreats is especially conspicuous on the lower shelf, where northeast trending beaches are interrupted by northwest trending tidal channels. However, overall transgression of the Sweetgrass arch was complete at this time, and only a part of the Central Montana Platform (Belt Island of Imlay *et al.*, 1948) remained emergent.

UPPER JURASSIC VANGUARD BASIN

The Upper Jurassic Vanguard basin represents not only an expansion of the Piper marine region, but also a deepening of the tectonic basin. The centre of the basin shifted from southern Saskatchewan to eastern North Dakota and central Montana (Fig. 9), and its geometry reflects the more nearly regular outline of the present structural form. Inundation of the central Montana uplift was completed by the Oxfordian, in particular, Upper Vanguard time.

Submersion of the western structural region led to the widespread distribution of the Rierdon and Swift shales. Large bodies of regressive sandstone prograded into parts of the basin. These probably reflect counterpart uplift of more distant structural regions; they are especially associated with structural blocks near basin margins. Basin deepening initially outpaced sediment influx, creating starved basin facies in the Rierdon lithotope.

In general, all sandstones are characterized by distal glauconitic argillaceous facies; coastal and deltaic sandstones have been largely eliminated by post-Vanguard erosion. Those that are present occur as dissected remnants along the northwestern rim of the basin as equivalents of the Rierdon and Swift shales. All sand bodies apparently originate from point sources and none are continuous over the basin, nor are they necessarily of the same age. Sand facies are vertically most coherent along the eastern flank of the basin in Saskatchewan, Manitoba and the Dakotas.

As defined by Milner and Thomas (1954), the Vanguard Formation overlies the Shaunavon Formation and is overlain by the Jura-Cretaceous Blairmore (*i.e.*, Mannville) Formation or Group (Christopher, 1974). Theses authors' subdivision of the Vanguard into lower, middle and upper members, is applicable only to southwestern Saskatchewan where the middle member is expressed as a sandstone unit between longitudes 108° 30' and 106°. There is general agreement that the lower member correlates with all or part of the Rierdon Formation of Montana and southwestern Alberta, and that the upper member correlates with the overlying Swift Formation. Opinions, however, diverge on correlation of the middle member. Francis (1956) and Springer *et al.* (1964, p. 147) place the member in the Swift Formation, but Peterson)1957) divides it into Rierdon and Swift correlatives. Christopher (1974, p. 38) recognizes this dichotomy but places all of the member in the Rierdon. This is based upon the following observations: 1) the Middle Vanguard is mostly a clinothem equivalent to a Rierdon fondothem (Rich, 1951); 2) the upper third, which is equivalent to the belemnite battlefield zone at the base of the Swift Formation in the Little Rocky Mountains of northern Montana, nonetheless underlies an unconformity at the base of the Upper Vanguard; and 3) the Middle Vanguard is not present in the type areas of the Rierdon and Swift Formations of western Montana. Christopher raised the Vanguard to group status. He also named and raised to formation status the Rush Lake Shale, the Roseray Formation and the Masefield Shale as nomenclatural replacement respectively of the lower, middle and upper members of the Vanguard Formation.

The Rierdon Subgroup

The Rush Lake Shale comprises dark green grey, calcareous shale and mudstone and light green grey marlstone. The fossils *Rhynchonella gnathopora* Meek, *Gryphaea nebrascensis* Meek and Hayden, *Kepplerites cf. rocky montanus* Imlay, *Arctocephalites cf. gracilis* Spath and *Arctocephalites cf. sawtoothensis* Imlay are characteristic of the Rush Lake-Rierdon Shales (Paterson,1968). The basal contact is discon-

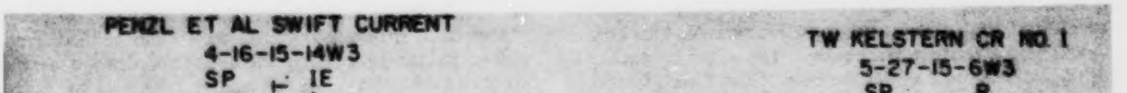

Fig. 10 - Reference wells of the Roseray Formation showing the relationship of diachronous sandstone clinothems to the Rierdon Shales in southwestern Saskatchewan.

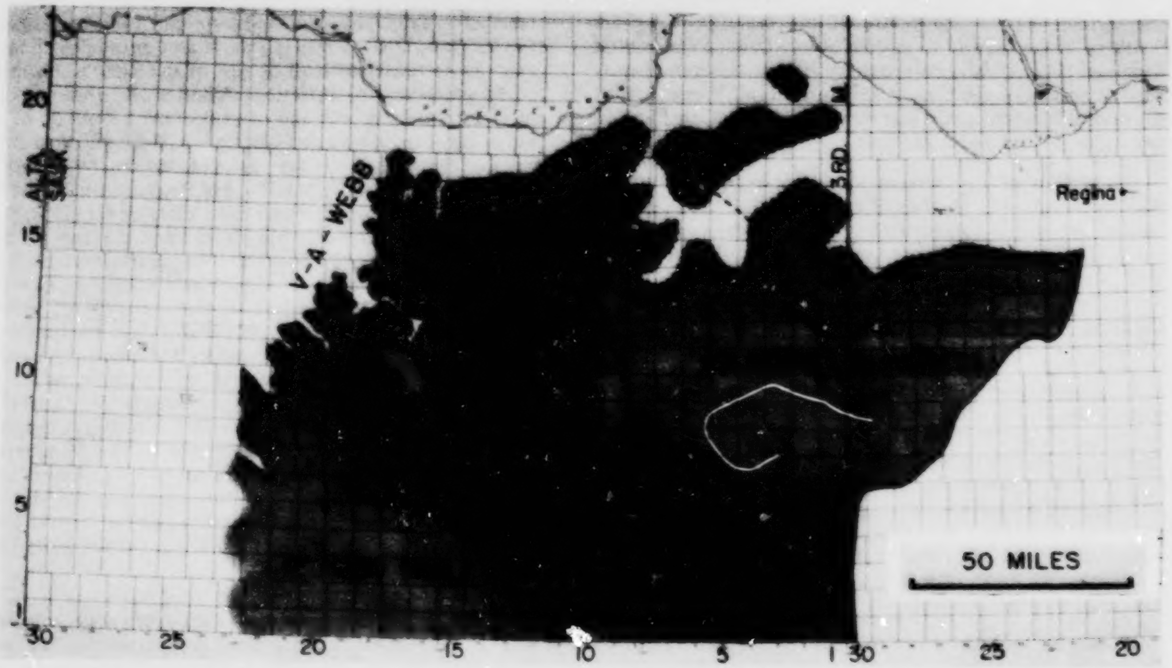

Fig. 11 - Map of the Roseray clinothems in southwestern Saskatchewan (from Christopher, 1974).

formable on the Shaunavon Formation west of longiutde 108° as well as to the south on the central Montana uplift. To the east, because of shale-out in the upper Shaunavon, this contact is picked on a resistive marker bed. The upper contact of the Rush Lake Shale is taken at the base of the Roseray sandstone body. The Rierdon subgroup is recognised outside the geographic area of the Roseray sandstone. The top of the subgroup is considered to be the horizon of the uppermost Roseray clinothem, named the Canopus. This marker bed is traceable across the Williston Basin proper, wherever the Upper Vanguard is present. The Rierdon subgroup thickens basinward from its erosional edge to 370 ft in the contiguous region of Saskatchewan, North Dakota and Montana (Peterson, 1957; Fig. 4).

The Roseray Formation includes a central body dominated by quartzose sandstone that is fine grained, well sorted, about equally subrounded and subangular, massive to horizontally laminated, and permeable (being only partially cemented with calcite or silica or weakly indurated with white to green kaolinitic clay and dark grey illitic clay). Scattered sphaerosiderite-speckled kaolin layers and dark grey marine shale are also conspicuous. Internally the formation constitutes sandstone beds that slope eastward and southeastward (oldest to youngest respectively) through the formation in the manner of foreslope beds. Each unit shales into the Rierdon shale lithosome (Christopher, 1974,). Those belonging to the older half of the Roseray descend through the Rush Lake Shale (Fig. 9), whereas the younger beds pass laterally into the upper part of the Rierdon Shale. Individually, these component beds "recapitulate" the facies distribution of the whole, *i.e.*, each displays the basinward decrease in grain size and shift in the argillaceous spectrum from sideritic kaolin to glauconitic illite.

On geophysical logs the Roseray Formation is best delineated by the gamma ray and sonic curves, on which it is expressed as pronounced, flat, deflections reflecting porous, well sorted sandstones. Up the depositional slope these curves are indented by thin, weak negative responses of the gamma ray curve and mild positive deflections on the sonic signature resulting from kaolin-undurated horizons that separate the permeable sandstones. Down slope, where the sandstone beds are locally differentiated by marine shale tongues, the permeable sandstones are indicated on the sonic curve by negative responses the counterparts of those on the gamma ray curve. The sandstone beds are correlatable wherever well spacing is dense. On this basis, ten beds are informally named (younging from west to east): Verlo, Antelope, Webb, Beverley, Java, Duncairn, Neidpath, Kelstern, Congress and Canopus. The beds older than Kelstern not only slope across the Roseray lithosome, but also fall asymptotically through the Rush Lake Shale, in which they are traceable as calcareous marker beds. The Kelstern, Congress and Canopus beds simply pass laterally into the Rierdon Shale as a wedge of calcareous glauconitic shale and mudstone thickening southeast toward the centre of the williston Basin. In terms of their spatial disposition, these beds more or less conform to the concept of Rich (1951) and to that of Oliver and Cowper (1963) for the Ireton shale basin of central Alberta *i.e.*, they are clinobeds and fondobeds. The Roseray clinobeds are essentially time-parallel units, although in aggregate, they constitute the diachronous Roseray Formation. No more than three of the clinobeds defined in the Roseray appear in the Formation at any given geographic point.

As shown in Figures 10 and 11, each successive clinobed, ending with the Neidpath, is more extensive eastward and southward. The Kelstern, Congress and Canopus beds represent a northerly onlap in the central part of the area. In total the Roseray lithosome forms a regressive tongue of sandstone that terminates the Rierdon lithosome in the Swift Current region. However, the intercalated marine fossiliferous shales, calcite-cemented marine pavements and continental sideritic kaolin-indurated pavements on truncation surfaces indicate this relationship to be complex. Regionally, the thickness of the Formation ranges from 45 to 160 ft; thicknesses greater than 100 ft represent shale contents in excess of 40%. The clinobeds (Verlo to Neidpath) are up to 70 ft thick; thickness decreases toward the margins to yield a lensoid geometry in cross section.

The Rierdon Shale east, southeast and beyond the edge of the Roseray Formation is mostly time-equivalent to the Roseray, *i.e.*, the lithosome is younger than the Rush Lake Shale. This is so because the source of Roseray lay to the northwest in southwestern Saskatchewan; sands were deposited to the southeast on a progradational slope of stretched sigmoidal shape dipping into what was in effect a starved basin. This Rush Lake-Rierdon relationship is depicted in Figure 12, wherein the Rush Lake Shale is labelled pre-Webb. The detailed correlation is shown in Plate II of Christopher (1974). Sandstone clinobeds equivalent to the Rush Lake fondothem are postulated to have been deposited in the northwest beyond the pre-Mannville erosion edge.

Pre-Webb sandstones in the Rierdon Shale are present in the extreme southeastern part of Saskatchewan as well as in southwestern Manitoba; they lie unconformably on the Shaunavon Formation or its marker bed. These sandstones are similar to Gravelbourg and Shaunavon sandstones in the region: they are fine grained, muscovitic, quartzose sandstones indurated with medium green grey marlstone, and they are dissected by white, coarser grained, kaolinitic and sideritic channel sandstones.

On the southeastern side of the Williston Basin, Peterson (1957, Fig. 6) shows the pre-Webb shales to be onlapped by the Beverley fondothem (his Rierdon "A" which becomes the Stockade Beaver Shale in the Black Hills area of the Dakotas). By the same correlation, the overlying Hulett Sandstone is a southern counterpart of the pre-Kelstern Roseray.

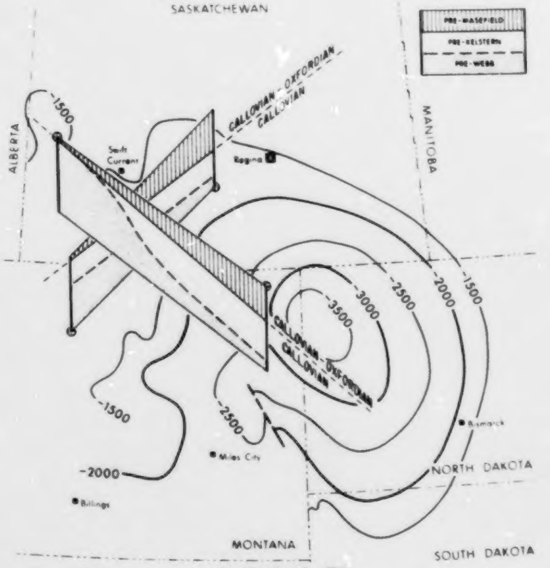

Fig. 12 - Panel diagram showing the regional diachroneity of the Rierdon subgroup in the northern Williston basin region (Christopher, 1974).

The Masefield Shale is largely a dark to medium green-grey shale, calcareous in the lower half, and sandy in the uppermost quarter near the International border. The formation overlies the Rierdon Shale in the southeast with a contact well defined by the Canopus marker bed. Westward it rests on the Roseray Formation, and west of the oilfield district it once again overlies the Rierdon Shale. Near the Alberta border the Masefield Shale contact transects the Rierdon Shale as demonstrated by Brooke and Braun (1972, Chart #23) with faunal evidence. This contact is the best mapping datum in the Vanguard group; in core, it appears as a thin, calcareous, fine, quartzose, locally glauconitic, sandstone bed on a disconformity (e.g., in Tidewater Beverley Crown No. 1 13-14-15-5W3 at 3357 ft). The Masefield Shales is severely truncated by the overlying Mannville Group. Nontheless, it is characterised by a uniform geophysical log signature similar to that of the Rierdon Shale (but with lower amplitude) throughout the geographic area of the formation. Southward into Montana the signature increases in amplitude upward, signifying proximity of the Swift Sandstone in that region.

The Masefield Shale correlates with the Swift Shale of the central Williston Basin region in North Dakota and Montana. The upper part of the Swift Formation is typically described as fine grained, calcareous, glauconitic sandstone, thinly interbedded with dark grey green calcareous shale (Imlay *et al.*, 1948). This is a facies similar to that of the distal beds of the underlying Roseray Formation. In Saskatchewan, these Swift sands occur in the upper part of the Masefield interval near the U.S. border. Because of post-Vanguard erosion across the southerly dipping Jurassic strata, much of this sandstone has been eroded in Saskatchewan. Virtually the entire shale facies passes into calcareous, glauconitic channel sandstones containing abundant *Ostrea* in the Great Falls-Fergus basin of central Montana. In the basin centre, the Masefield shale attains a thickness of 330 ft.

The Swift Formation as traced across the central Montana platform into the Williston Basin proper may include an ambiguity. Cobban's (1945) type Swift Formation is located at the Swift reservoir in the Sawtooth Range; the Formation is traceable onto the Sweetgrass Arch. In their description of the type section Imlay *et al.* (1948) divided the formation into an upper sandstone and a lower shale, but note certain lithological 'peculiarities'. To quote, "The sandstone member differs from the sandstone facies farther south by being thinner bedded, and by containing many more partings of dark, fissile, finely micaceous shale . . . the underlying shale member differs from the shaly facies of south-central Montana by being noncalcareous and very finely micaceous". Hayes (1983) correlates the Swift Formation, particularly the so-called ribbon sandstone, with Christopher's (1974) S1 unit of the post-Vanguard Success Formation. This is based upon recognition of Upper Jurassic palynomorphs in the S1 unit in Tidewater Frontier Crown No. 1 (13-21-3-20W3), and geophysical log correlation.

The type area of the Success Formation S1 unit is on the Swift Current Platform (Christopher, 1974 p. 18), which forms an outlying region on the northeastern flank of the Central Montana Platform. The S1 member is made up of bedding groups 1 to 18 ft thick, consisting of quartzose, very fine

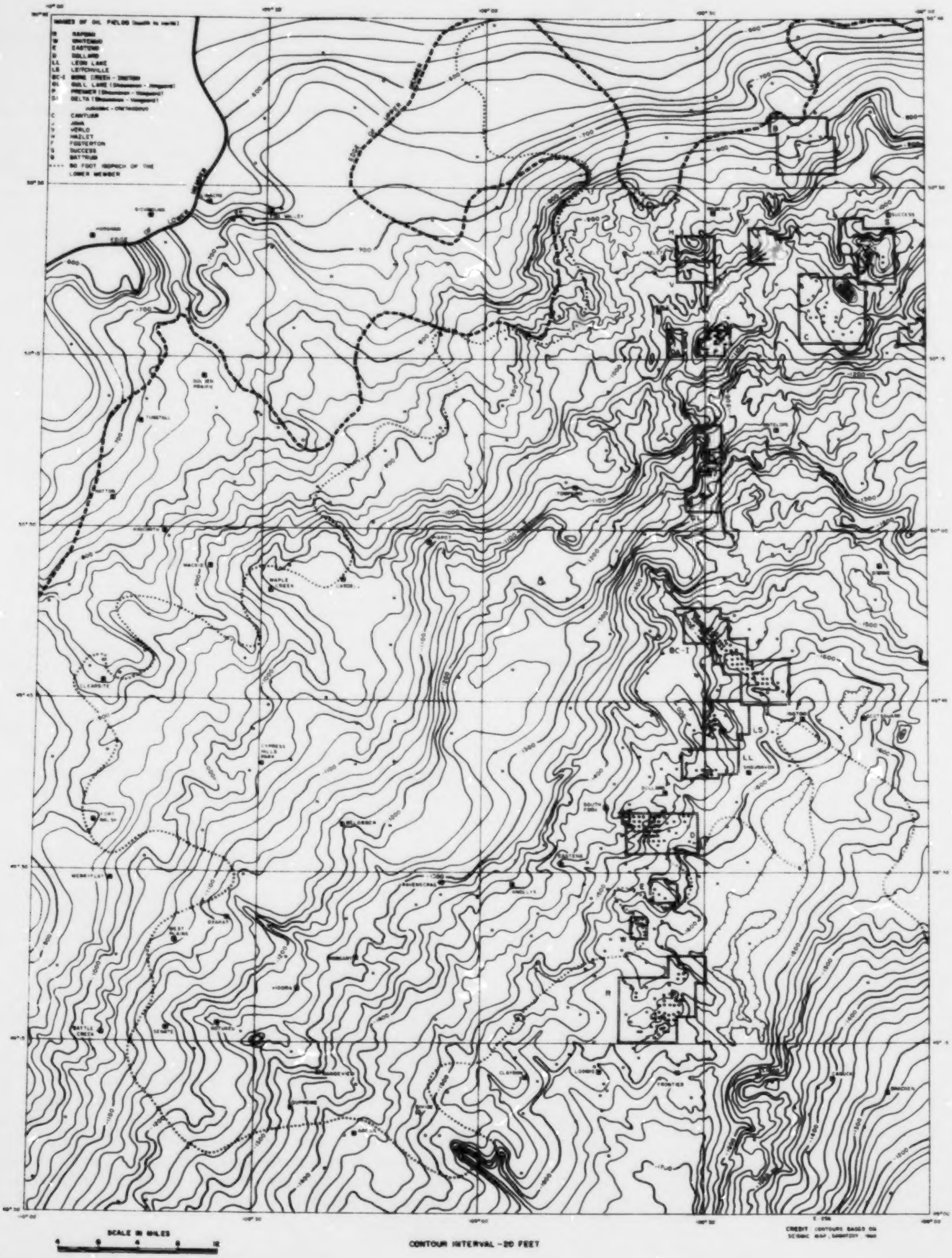
NAMES OF OIL FIELDS (south to north)
R RAPDAN
W WHITEMUD
E EASTEND
D DOLLARD
LL LEON LAKE
LS LEITCHVILLE
BC-I BONE CREEK - INSTOW
GL GULL LAKE (Shaunavon - Vanguard)
P PREMIER (Shaunavon - Vanguard)
DI DELTA (Shaunavon - Vanguard)
C CANTUAR
V VERLO
H HAZLET
F FOSTERTON
S SUCCESS
B BATTRUM
50 FOOT ISOPACH OF THE LOWER MEMBER
SCALE IN MILES
0 2 4 8 12
CONTOUR INTERVAL - 20 FEET
CREDIT: CONTOURS BASED ON SEISMIC MAP
-700
-800
-900
-1000
-1100
-1200
-1300
-1500
-1600

Fig. 13 - Structure map on the Lower Member of the Shaunavon Formation in southwestern Saskatchewan showing locations of the Shaunavon, Roseray and Success oilfields (from Christopher, 1964, Fig. 1).

Pool	year discovered	initial oil in place (1 × 10^6) bbls	Recoverable Reserves (1 × 10^6) bbls	Remaining Reserves (1 × 10^6) bbls	depth (feet)	Avge Net pay	Avge porosity
			Shaunavon Formation				
Bone Creek - Instow	1954	227.52	63.16	8.25	4360	15	13.8
Delta	1956	85.18	17.81	2.62	3460	22.5	20.4
Dollard	1953	181.75	84.56	5.2	4550	14.4	20.0
Rapdan	1953	167.75	22.4	6.0	4560	15.0	15.5
Total 1		**667.76**	**187.93**	**22.07**			
			Roseray-Cantuar Formations				
Battrum	1955	293.37	68.31	23.56	2870	34.7	26.0
Cantuar	1955	292.0	42.87	8.81	3055	12.5	26.0
Fosterton	1952	157.68	65.81	7.68	3170	32.0	28.8
Total 2		**743.05**	**177.99**	**40.05**			
Total 1 + 2		1,404.81	364.92	62.12			
Total all fields		2,375.05	556.03	101.82			

Table 1 - Main oilfields of the Shaunavon-Roseray-Success trend (after Reservoir Annual 1983, Saskatchewan Energy & Mines).

grained, subangular, grey white to light grey, kaolin indurated sandstone intermixed and interlaminated with quartzose, coarse grained, slightly to heavily carbonaceous, lavender grey to black siltstone with sparse to abundant layers of sphaerosiderite. Muscovite is abundant throughout. Locally, the carbonaceous beds are weakly bioturbated, contorted, brecciated and faulted on a small scale. In thicker deposits associated with paleotopographic valleys, accessory glauconite occurs. The laminae in the S1 coarsen upward internally, as does the unit as a whole, with the exception of a variable, locally conglomeratic, basal bed. Where the unit is thicker bedded, ripple and small scale festoon cross lamination is seen. Unit S1 thickens to a maximum of 100 ft in the paleotopographic lows on the sub-Success unconformity. In southeastern Saskatchewan, across the 30-mile stretch along longitude 104° between the International border and Township 6, a 245 ft section of the Masefield Shale is truncated beneath this unconformity.

Not only is the lithology "peculiar", but foraminiferal assemblages typical of the Vanguard are not found in the Success S1 unit. Neither Brooke and Braun (1972) nor Hayes (1983) recovered any formation forams in Saskatchewan, nor from Hayes' Swift Formation in Alberta. The Jurassic age assignment is based on palynomorphs. Using the micropaleontological data of Brooke and Braun (1972), Christopher, (1974, Fig. 16) correlated geophysical logs south to the Fergus-Great Falls basin from the reference well (Tidewater Frontier Crown No. 1). The S1 unit apparently correlates with the Morrison Formation of that region. Assuming Hayes' correlation from the Sweetgrass Arch of Alberta is accurate, it thus appears that there are two formations bearing the name of 'Swift', and that these are separated by an unconformity. This unconformity is the J-5 of Pipiringos and O'Sullivan (1978, p. A25), separating the Morrison from the Williston Basin Swift, *i.e.*, the Masefield Shale.

The Success S1 facies of white, kaolinitic sandstones laminated with black and lavender grey shales are similar to the continental to proximal marine shales of the Rierdon Formation. Likewise, the local presence of glauconite suggests a marine transition. However, prograding sediments of the Jura-Cretaceous fluviatile-lacustrine depositional regimes would have encroached extensively into the depositional Williston Basin at that time. These sediments are Morrison in the south and Success in the north. Just as the former is widespread across southern Montana and the Dakotas, the latter is distributed across Manitoba, Saskatchewan and southeastern Alberta.

SUPERJACENT STRATA

The Swift Formation and its equivalents are overlain by the Lakota Formation of the Inyan Kara Group in the southern and central Williston Basin, by the Kootenai Formation in western Montana, by the Blairmore in southern Alberta, by the S2 member of the Success Formation in Saskatchewan, and by the Swan River Formation in Manitoba. At the bases, these formations are Early Cretaceous (pre-Albian); they overlie the Jurassic System with an erosional unconformity.

In Saskatchewan, the S2 member of the Success Formation, like the underlying S1 member, comprises quartzose sandstones in a white kaolinitic matrix, but it is composed of dominantly medium and coarse grained sand with trough cross bedded fining-upward channel sequences up to 50 ft thick. The Success Formation, though widely distributed on the Central Montana Platform and the Sweetgrass Arch, is deeply dissected. The relief is infilled with strata of the Cantuar Formation to a depth as great as 250 ft. In southwestern Saskatchewan, the more permeable Sucess and Roseray Formations are carved into mesas and buttes isolated from the erosional front by valleys. The less permeable valley fills act as seals to oil reservoirs found in this region. A description of this topography and the succeeding Cantuar basin is given by Christopher (1974, 1980, in press).

THE OILFIELDS OF SOUTHWESTERN SASKATCHEWAN

The major oilfield district in Lower Mesozoic strata of the northern Williston Basin is that in the Jurassic of southwestern Saskatchewan. The fields are distributed along a north trending belt at longitude 150° 30" between latitudes 49° 15" and

50° 35″ (Fig. 13). There are 21 designated pools constituting a complex of reservoirs in the Shaunavon, Roseray and Success Formations. The Shaunavon pools form the belt south of Latitude 50° 15″; Roseray-Success pools occupy the region to the north. Dual Shaunavon-Roseray production is obtained from the Gull Lake, Suffield and Premier pools midway in the belt. About 65% of the initial recoverable reserves were in 7 pool complexes. These are the Shaunavon, Rapdan, Dollard and Bone Creek-Instow Fields (south to north) and the Roseray-Success, Cantuar, Fosterton and Battrum Fields (Table 1). These fields also retain 61% (101.82 million barrels) of the initial 556.03 million barrels of recoverable reserves as of March 31, 1982.

Structurally, the oilfields occupy the northwestern flank of the northeasterly trending Shaunavon syncline; they are situated on terraces stepping up to the north. Depths range from 4,500 feet in the south to 3,850 feet in the north.

The Shaunavon Oilfields

Each unit of the upper member of the Shaunavon Formation of southwestern Saskatchewan is composed of shoreline sandstones, partially or wholly cemented with calcite, and in the case of Unit 2, with dolomite. These deposits form linear bodies that more or less trend northeast along the strike of the Shaunavon shelf. On the higher reaches of the shelf, however, they coalesce into sandstone sheets because of the relatively low topographic gradients on the large aprons (Fig. 7), and the large scale of the repeated marine oscillations across such areas. However, depositional gradients steepened along the shelf margin adjacent to the Shaunavon syncline, so that changes in sea level across this belt were accompanied by smaller lateral shifts of the shoreline. Thus shoreline sandstone bodies at the lowest still-stands of sea level were preserved because transgression and regression occurred mostly in the paleotopographically higher regions to the west. Likewise, sands which were widespread to the west yielded abruptly to muds in the east because of the rapid decline of the sea floor into the syncline. Shaunavon oil reservoirs are found in the low still-stand shore and nearshore deposits. More specifically, these are northeasterly oriented beach and shoal sandstone bodies and northwest trending channel fills of sand and oyster shards.

The Rapdan (R) and Whitemud (W) oilfields (Fig. 8) are situated in twin beach forms that are the largest and morphologically most accurate of their type. The Rapdan beach deposits are 15 to 60 ft thick and cover an area 9 mi. long and 4.5 mi. wide. They consist of the quartzose sandy and argillaceous dolomite, dolomitic sandstone and quartz-nucleated dolomitic oolites that characterize Unit S2. The oolites flank the southeastern front of the beach sandstone body. They form two wedges (up to 50 ft thick at their southern edge) that penetrate the main body of the beach northward as far as 2 miles, in the manner of beach blowouts or tidal inlets (Christopher, 1964, Fig. 23). The Whitemud beach deposit lies to the west. It is 1 to 2 mi. wide and its definition sharpens northeastward to a split-like termination. The lithological constituents are similar to those of Rapdan, but the quartz-nucleated oolites increase proportionately southward towards the junction with the Rapdan deposits.

The beach sandstones are separated laterally by tan coloured dolomitic mudstones, marlstones and black shales. These occupy a paleotopographic depression and thus represent deposits typical of a lagoon or esturary. In the beach deposits the pervasive presence of the tan coloured dolomite matrix as well as replacement of aragonite by dolomite in the oolites suggest subaerial exposure and penecontemporaneous dolomitization. Structurally much of the Rapdan beach deposit morphologically duplicates the isopach pattern (Figs. 8 and 13). However, the Whitemud Field is now at a higher elevation. This indicates that the Rapdan beach and lagoonal deposits have subsided relative to the Whitemud area in the west.

The Bone Creek-Instow (BC-I) reservoir body is a coquina that includes fine grained quartzose sand variably cemented with calcite. It is 2 mi. wide, trends northwest for 12 mi. (Fig. 8), and infills a channel eroded into units U2 and U3. The channel coincides with an ancestral structural trough on the lower member (Fig. 13). It represents the last of a series of similar deposits, as revealed by remnants of older sandstone beds preserved along the flanks of the trough. Mudstone and shale, which constitute a high proportion of unit U1 in the channel, decrease upward through unit U2. Unit U3 is almost wholly composed of calcarenitic and calciruditic sandstone. It appears that the trough served as a settling basin for mud, early in its history, before becoming a locus of downslope sediment movement caused by tidal currents and falling sea levels.

The Dollard (D) oilfield is similarly dominated by sandstone and bioclastic calcirudite of U3, although the pelecypod shells are more fragmented. These beds blanket a southeasterly dipping slope as well as a northwesterly trending intramember channel, one-eighth to one mile wide, which terminates the deposit along the southwestern flank. The base of the channel successively intersects units U2, U1 and the upper 17 ft of the lower member as it descends stepwise toward the southwest on slopes as steep as 40 ft/mi. (Christopher, 1964, Fig. 25). Coquinas are concentrated in the channel and the lower part of the unit overall, whereas sandstone characterizes the flanking beach deposit and the upper part of the deposit in general. The Dollard beach deposit, as well as the similar but older subunit U2d sand bodies to the northeast, appear to be products of a southwesterly drift introducing sediments from the Bone Creek-Instow trough.

The Roseray-Success Oilfield District

The Upper Jurassic and Lower Cretaceous reservoirs of this district vary from 1 to 23 mi.^{2} in area. They lie along the northwestern perimeter of the Roseray Formation, some 150 ft above the Shaunavon Formation. At Gull Lake and Suffield oil is trapped by the updip western facies edge of the Roseray Formation and by Cantuar valley fill to the north and east. The remaining fields (Premier, Verlo, Hazlet, Fosterton, Cantuar, Success and Battrum) occupy buttes and mesas isolated by less permeable Cantuar sediments (Fig. 14). The Cantuar and Success reservoirs also include the overlying Jura-Cretaceous Success Formation.

Lateral permeability barriers and the effect of a southeasterly hydrodynamic gradient make possible the distribution of oil pools over a 200 ft range in structural elevation (from −780 ft in the southeast to −580 ft in the northwest). The same factors offset buoyancy forces that would drive oil into the argillaceous sandstones and sandy mudstones of the Cantuar Formation. The oil/water contact dips to the southeast, but more gently than the reservoir strata, so that oil accumulations are concentrated in beds progressively higher stratigraphically to the southeast.

The northwestern oilfields of Battrum, Fosterton and Verlo yield oil primarily from the Roseray Formation, whereas the more southern and eastern Cantuar, Beverley and Gull Lake Fields produce primarily from the Success Formation; to some

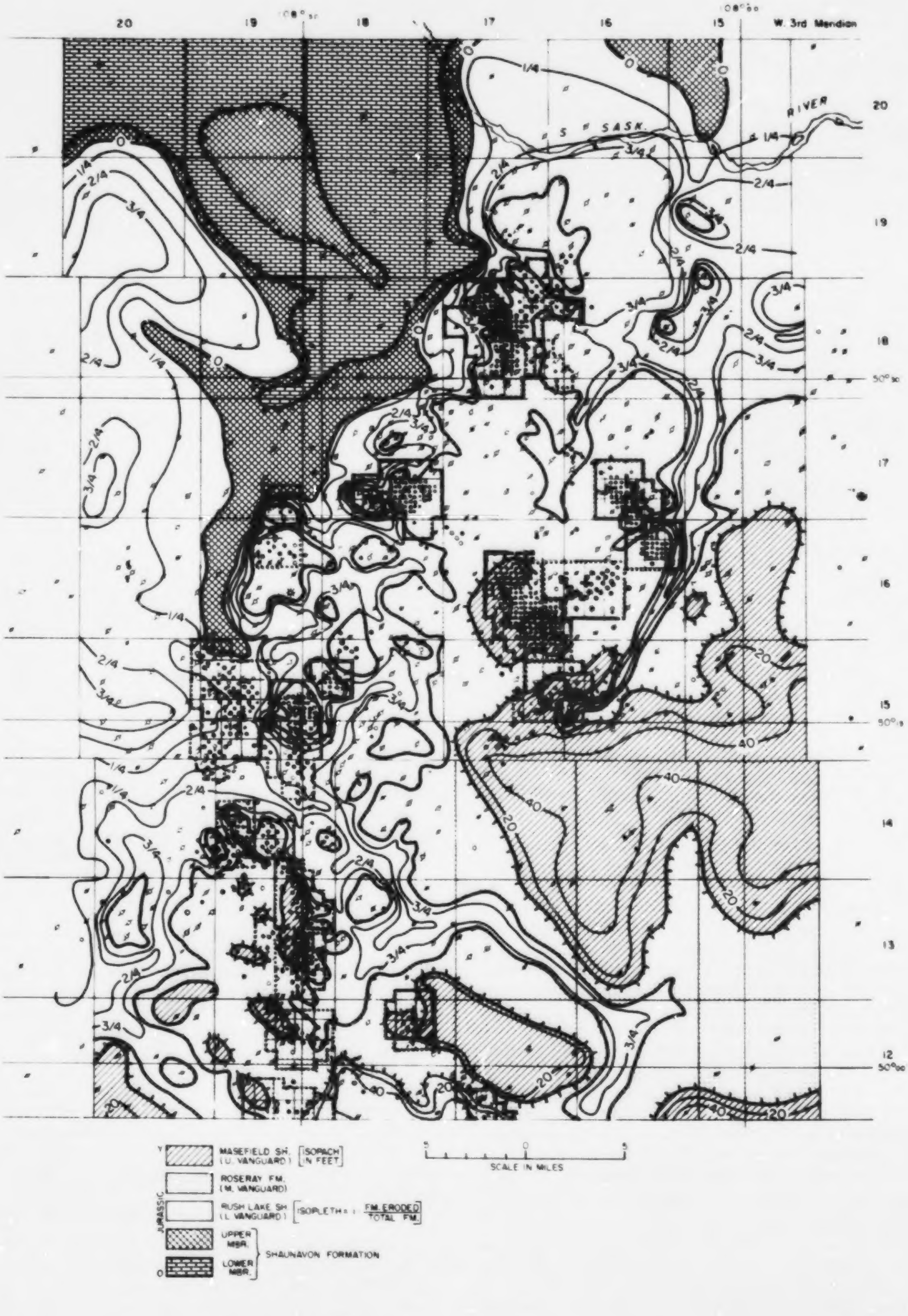
20
19
108°30
18
17
16
108°00
15
W. 3rd Meridian
20
19
18
50°30
17
16
15
50°15
14
13
12
50°00
S. SASK. RIVER
0
1/4
2/4
3/4
20
40
JURASSIC
MASEFIELD SH. (U. VANGUARD) [ISOPACH IN FEET]
ROSERAY FM. (M. VANGUARD)
RUSH LAKE SH. (L. VANGUARD) [ISOPLETH = 1 - FM. ERODED / TOTAL FM.]
UPPER MBR.
LOWER MBR.
SHAUNAVON FORMATION
5
0
5
SCALE IN MILES

Fig. 14 - Sub-Cantuar paleogeologic map of the Jurassic in the oilfield district of southwestern Saskatchewan (from Christopher *et al.*, 1971, Fig. 25).

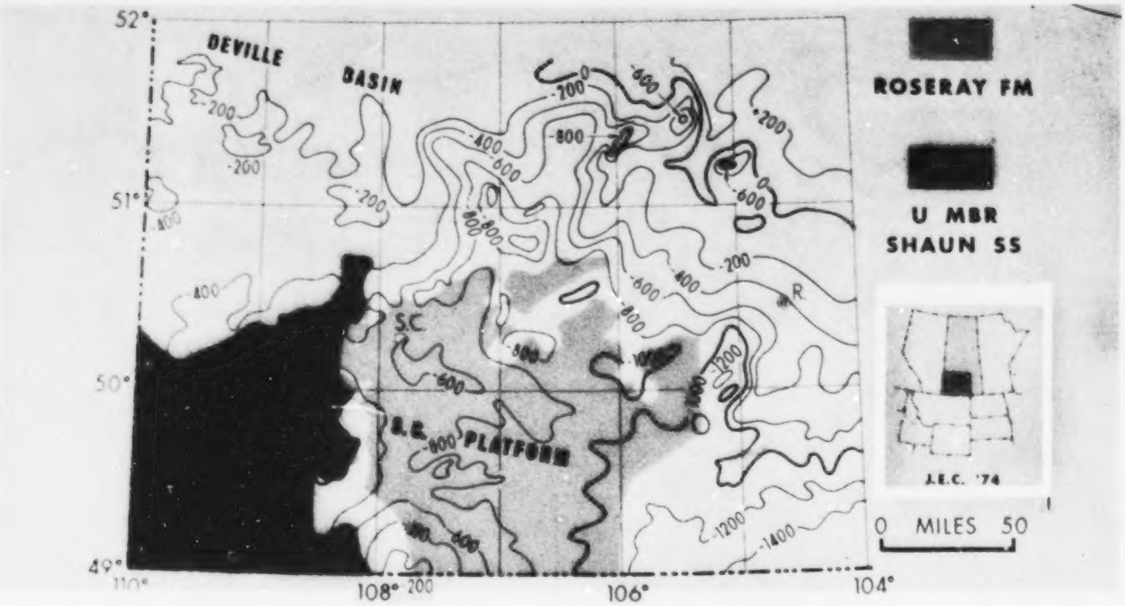

Fig. 15 - Areal distribution of the Roseray and Shaunavon Formations as related to structure on the Shaunavon Formation in southwestern Saskatchewan.

extent, production is from both formations in all fields. To the southeast, hydrodynamic gradients are not uniform in that the oil water contact is "perched" by transecting permeability barriers formed by Cantuar valley fills.

The reservoirs of the Success and Roseray Formations are generally contiguous, except for the western portion of the Cantuar and the Beverley oilfields where the Masefield Shale intervenes. However, all dual reservoirs are stratified by argillaceous beds of low permeability, whether they be Roseray marine shale tongues or Roseray and Success sideritic, silty argillaceous pavements.

The spatial coincidence of the Roseray-Success oil reservoirs with the Shaunavon in the northern part of the Shaunavon syncline arises from a sedimentary paradox: whereas the Shaunavon fields occur at the downdip edge of the sandstone facies, the Roseray reservoirs occur at the updip edge of the Roseray sandstone facies (Fig. 15). As mentioned previously, the Shaunavon sedimentary bodies are more or less controlled by paleotopography of the Shaunavon shelf as well as the present structural setting. The depositional base level of the Roseray Formation was created by uplift of the Swift Current Platform. This uplift reversed the sedimentation sense of the region along the Shaunavon syncline, such that the Roserary shelf overlooked the Shaunavon and thereby caused Roseray sands to shale out westward. Uplift of the Swift Current Platform reached its acme in the Early Cretaceous. Thereby the entire northern perimeter of the Williston Basin was uplifted and the Jurassic basin was effectively terminated.

It is estimated that southwestern Saskatchewan was uplifted by as much as 1,900 ft in the pre-Aptian (Christopher, 1980, in press). This would have created a regional dome, with the Shaunavon syncline as a graben superimposed on it. This structure is the one feature common to all of the reservoirs; it apparently accounts for vertical transfer of oil from Paleozoic reservoirs to the Jurassic system along fracture and fault systems.

SUMMARY AND CONCLUSIONS

The tectonic Williston Basin persisted as a centrally controlled, topographically negative region throughout the Paleozoic to the end of the Jurassic. Relatively rapidly subsiding troughs concommitant with local uplift of structural blocks strongly modified the flanking structural regions at different times and places as subsidence progressed.

Epeirogenic uplift following the Appalachian orogeny reached its acme in the Triassic. At this time erosional stripping of sediments apparently reduced the region to a basic configuration comprising a trough trending northeast from Wyoming into the Amaranth sub-basin of Manitoba, and a similar trough projecting northwest from it across the basin center into Saskatchewan.

The directional trends of the Triassic basin controlled the sedimentation patterns of the Middle Jurassic marine basin. The thin Middle Jurassic sequence is a product of evaporative and restricted environments, reflecting weak sediment influx relative to basin size. Upper Jurassic coarse clastics represent near shore and offshore sand tongues limited in distribution and linked to point sources on the basin margin.

The major oilfield system occurs in the downdip low stillstand shoreline sand bodies of the Shaunavon Formation, and in the updip edge of the proximal marine sands of the Roseray Formation as defined by the pre-Cretaceous erosional edge. Both facies and erosional edges are linked to the Shaunavon syncline, which is a trough terminating the Sweetgrass - central Montana structural region overlooking the basin.

In that petroleum source beds are not known to be present in the Jurassic of the basin (*cf.* van Delinder, this volume), it would appear that: 1) the Jurassic oil pools are linked by the fracture/fault systems of the syncline; and 2) that migration from Paleozoic source beds occurred when the structural platform region was tilted upward by Early Cretaceous uplift of the outlying Swift Current Platform. This uplift placed the Shaunavon syncline at the centre of a dome and tilted the opposing margins of the Shaunavon and Roseray Formations. Oil migration from deeper Paleozoic systems into Jurassic reservoirs would have occurred at this time. Slow collapse of the Swift Current Platform and continued subsidence of the Williston Basin led to restoration of the easterly dipping structural configuration. Oil is retained in the reservoirs by an easterly potentiometric gradient of formations waters flowing through updip semi-permeable barriers that trap oil in the Shaunavon and Roseray Formations. Oil shows in the Shaunavon Formation to the west of the fields may reflect oil that has bypassed the eastern traps. Similarly, oil shows in the Roseray Formation to the east of the fields may represent oil that has migrated eastward from structures that were emptied by late southeasterly tilt.

Prospects for future discoveries lie in:

1) locating Shaunavon structural and Roseray topographic highs north and west of the Shaunavon syncline;
2) defining a northeasterly trending, semi-permeable belt of sediments in the Shaunavon Formation to the west of the one flanking the updip margin of the oil field trend;
3) infill drilling between the fields;
4) Roseray structural highs to the east of the oil field belt; and
5) Paleozoic beds in the vicinity of the Shaunavon syncline.

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THE WASKADA LOWER AMARANTH (SPEARFISH) OIL POOL, SOUTHWESTERN MANITOBA: A MODEL FOR SPEARFISH EXPLORATION IN SASKATCHEWAN

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ABSTRACT

The Waskada Lower Amaranth Oil Pool was discovered in 1980 and as of the end of March 1984, has produced approximately 310,000 m^3 of oil. Secondary recovery through water flooding has been initiated throughout much of the pool and remaining recoverable reserves are estimated at close to 1.24 million m^3. This discovery has added significantly to provincial oil reserves and has reversed the trend of declining oil production in Manitoba.

The general geological setting of the Waskada pool (*i.e.*, basal Mesozoic red beds overlying erosionally truncated Mississippian carbonates) persists over much of southeastern Saskatchewan, making the area a prime hunting ground for Waskada-type pools. An understanding of the stratigraphy, structure, and trapping mechanism of the Waskada pool is essential in developing an exploration strategy for Spearfish pools in southeastern Saskatchewan.

INTRODUCTION

The Waskada Lower Amaranth Oil Pool was "discovered" in June of 1980 when Omega Hyrdocarbons Ltd. recompleted a former Mississippian producer in the stratigraphically higher Lower Member of the Amaranth Formation. This success initiated a development effort which, as of March 1984, had resulted in over 200 wells producing approximately 550 m^3 of oil per day from over 3200 productive hectares. This production accounts for over 25% of Manitoba's total oil production. Thus the Waskada discovery has contributed a significant addition to the province's productive capacity. Cumulative production as of March has exceeded 310,000 m^3 and total recoverable reserves are estimated at 1,241,560 m^3 (Manitoba Department of Energy and Mines, 1983). The Waskada Field is located in Townships 1 and 2, Ranges 25 and 26W1 immediately north of the International border and approximately 35 km east of the Saskatchewan border (Fig. 1).

The Lower Amaranth of Manitoba is correlative with the Lower Watrous of Saskatchewan and Upper Spearfish of North Dakota. These basal Mesozoic red beds unconformably overlie productive Mississippian carbonates throughout the northern part of the Williston Basin. This general geological setting suggests that much of southeastern Saskatchewan is prospective for Waskada-type pools.

The purpose of this paper is to discuss the Waskada Lower Amaranth Pool with this application in mind. The regional setting, lithology, stratigraphy, depositional environment, reservoir characteristics and production trends are described. Exploration problems specific to this kind of play are also discussed with an emphasis on the importance of understanding the nature of fluid movements across lithological boundaries.

REGIONAL SETTING

The sedimentary strata of southwestern Manitoba occur as a basinward thickening wedge of Paleozoic and Mesozoic strata on the northeastern flank of the Williston Basin. A major angular unconformity separates the Paleozoic and Mesozoic sections, and corresponds to a hiatus ranging from Late Mississippian through Early Jurassic. Basinward tilting of the Paleozoic strata also occurred during the hiatus, resulting in northeastward progressive erosional truncation of the Paleozoic strata at the unconformity surface. A sequence of Jurassic and Cretaceous strata onlaps the eroded Paleozoic surface. The Lower Member of the Amaranth Formation is the basal unit of the Mesozoic section and its stratigraphic position is shown in Figure 2.

Subjacent Paleozoic strata within the Waskada area comprise carbonates and evaporites of the Mississippian Mission Canyon and Charles Formations; and represent deposition of a regressive sequence of carbonates and evaporites prior to the ultimate retreat of Mississippian seas from the area. They are erosionally truncated, and in general form northwest trending subcrop belts at the unconformity surface.

The Lower Amaranth is overlain by evaporites of the Upper Amaranth which are in turn overlain by carbonates of the Reston Formation, both of Middle Jurassic age. The upper contact of the Lower Amaranth is believed to be conformable in Manitoba.

The onlap of the Lower Amaranth onto Paleozoic strata is shown in the stratigraphic cross-section from the Newburg producing area in North Dakota to the Waskada area (Fig. 3). Lower Amaranth sedimentation effectively filled in depressions on the Paleozoic erosional surface, as indicated by thickening of the basal units in the member. The marker at the top of the Lower Amaranth is thought to approximate a time-stratigraphic marker representing termination of the supply of clastics to the basin.

The basal sandstone is productive in the Newburg area of North Dakota (Interval A, Fig. 3). Its northerly pinchout accounts for the trap at Newburg. The sandstones in Interval C, which are water saturated in the Newburg area, form the updip reservoir beds at Waskada. This trap, however, is related to a lateral facies change within Interval C, rather than to an onlapping configuration as at Newburg.

Structure on the Lower Amaranth in the Waskada area is fairly regular, dipping to the southwest at about 4.2 m per km. This is an expression of post-depositional basinward tilting related to continued subsidence of the Williston Basin. Minor structural undulations may be the result of differential compaction and/or post-Lower Amaranth salt solution and collapse. No evidence of structural closure is seen, indicating that trapping is primarily stratigraphically controlled.

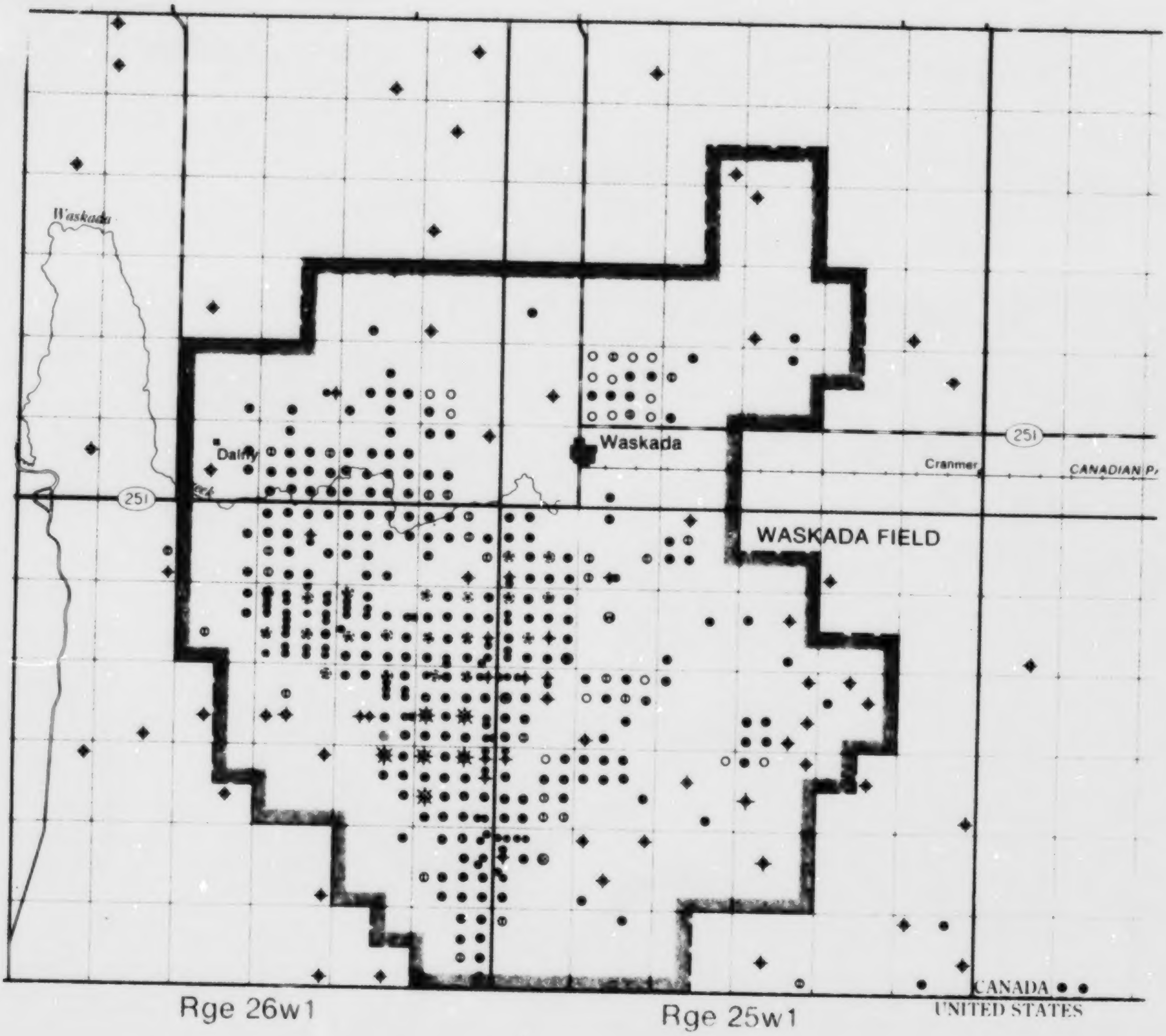
Waskada
Dalny
251
Waskada
251
Cranmer
CANADIAN P
WASKADA FIELD
CANADA
UNITED STATES
Rge 26w1
Rge 25w1

Fig. 1 - Waskada Field well location map.

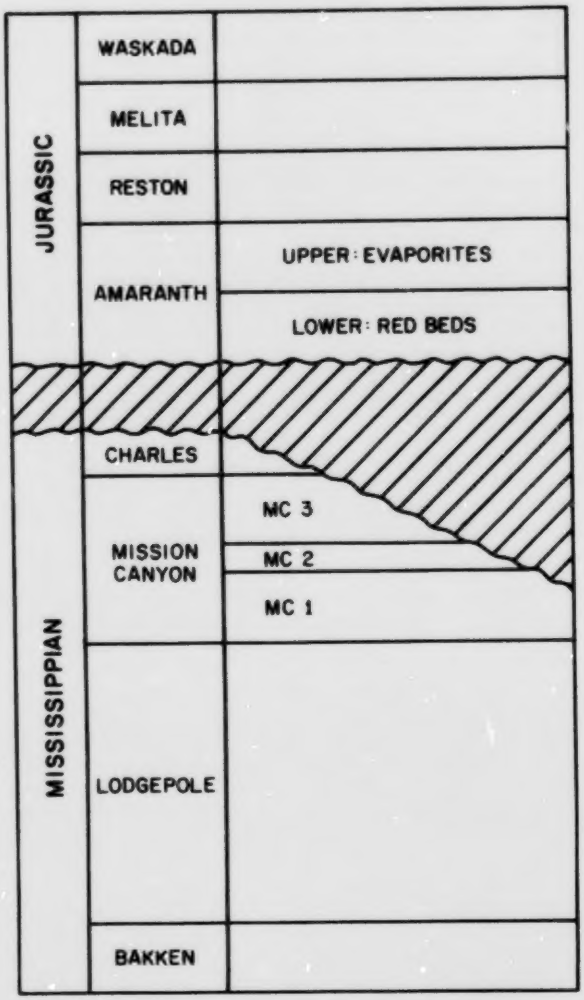
JURASSIC
WASKADA
MELITA
RESTON
AMARANTH
UPPER: EVAPORITES
LOWER: RED BEDS
MISSISSIPPIAN
CHARLES
MISSION CANYON
MC 3
MC 2
MC 1
LODGEPOLE
BAKKEN

Fig. 2 - Stratigraphic column.

LITHOLOGY

The dominant rock type of the Lower Amaranth consists of dolomitic siltstones and sandstones interbedded with argillaceous siltstones and shales exhibiting a mottled red to maroon colour. The term "red beds" has commonly been applied to this unit, as the basic character is similar to that of typical red bed sequences discussed in the literature (*e.g.*, Dunbar and Rodgers, 1957). Dolomite and anhydrite are important constituents. Dolomite is associated primarily with the finer grained silty material, whereas anhydrite occurs as pore-filling cement in the coarser-grained sandy material and as massive nodules and lenses. Four general lithological types can be recognized in the Waskada area.

INTERBEDDED SHALE/SILTSTONE/SANDSTONE

This lithology exhibits many variations in grain size, colour, and texture. Basically, it is mottled and generally maroon to light brown. Shale is usually maroon to dark red and the coarser grained interbeds are generally grey to light brown.

Characteristic of this facies is the conspicuous interbedding which ranges in thickness from less than 1 cm to about 5 cm. The beds are discontinuous and irregular with the coarser-grained components occurring as distinct lenses or pods, generally elongated horizontally or nearly horizontally. Contacts between beds are sharp and irregular, and give the rock a pseudo-brecciated appearance.

SILTSTONE

Siltstone occurs as beds up to 2 or 3 m in thickness. It is generally light grey to light green and dolomitic. Most grains are silt to fine sand size, but thin, discontinuous interbeds of coarser-grained material are common. Isolated, well rounded coarse quartz grains are abundant. Faint lamination (often inclined and contorted) is evident in places, but primary sedimentary structures are lacking in general. The distinction of this lithology from the interbedded lithology described above is the relative abundance of coarser clastic beds and the absence of appreciable shale content.

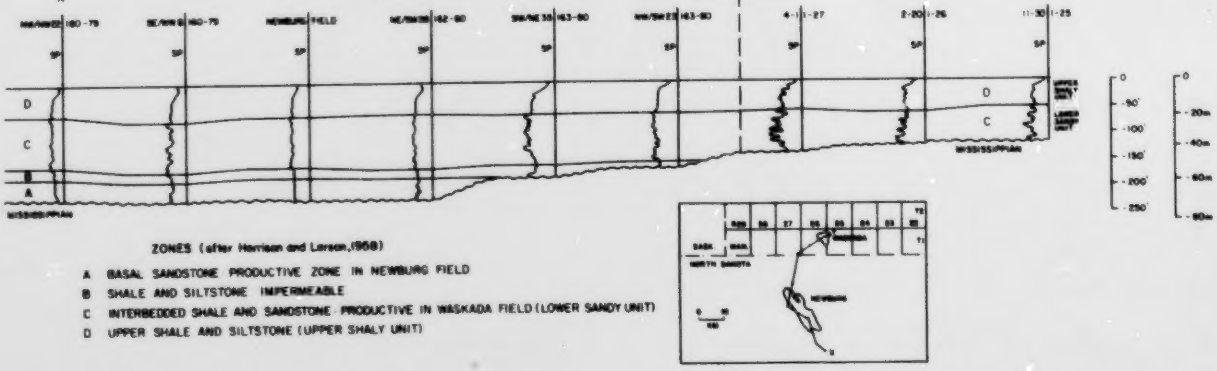
X
Y
N DAKOTA | MANITOBA
NEWBURG FIELD
4-1 1-27
2-20 1-26
11-30 1-25
SP
D
C
B
A
MISSISSIPPIAN
UPPER SHALY UNIT
LOWER SANDY UNIT
0
-50'
-100'
-150'
-200'
-250'
-20m
-40m
-60m
-80m
ZONES (after Harrison and Larson,1958)
A BASAL SANDSTONE PRODUCTIVE ZONE IN NEWBURG FIELD
B SHALE AND SILTSTONE IMPERMEABLE
C INTERBEDDED SHALE AND SANDSTONE PRODUCTIVE IN WASKADA FIELD (LOWER SANDY UNIT)
D UPPER SHALE AND SILTSTONE (UPPER SHALY UNIT)
SASK.
MAN.
NORTH DAKOTA
WASKADA
NEWBURG

Fig. 3 - Stratigraphic section from Newburg to Waskada.

LAMINATED SANDSTONE

This lithology occurs as distinct sandy beds up to 4 m thick with a wide range of grain sizes and primary sedimentary structures. Colour varies from light grey to greenish grey, and brown where oil stained. Grain size varies from medium to very fine sand. Sorting is variable, with the medium-grained sandstones showing a poorer degree of sorting. Roundness is also variable, with a tendency for the medium sized grains to be rounded and the finer grains to be subangular. The sandstones fall into the compositional range of quartz to feldspathic arenites. Quartz grains dominate, with 5 to 15% feldspar. Minor mafic grains commonly occur in thin laminae.

The relationship between the size of the intergranular spaces and the composition of the intergranular material is remarkably consistent. Medium-grained sandstones are cemented by anhydrite, whereas the fine and very-fine grained sandstones show a gradation to dolomitic matrix. This relationship also holds true in the interbedded lithology, where patches of anhydrite cement are associated with medium-grained interbeds in an otherwise dolomitic rock.

Primary sedimentary structures include horizontal lamination, cross-lamination inclinded up to 20°, and small scale current or ripple cross-lamination.

MASSIVE SANDSTONE

Massive sandstone occurs in beds less than 0.5 m thick and is usually associated with the laminated sandstones facies. Beds are generally light grey to reddish grey and coarse to medium-grained. Grains are predominately of quartz, and are subrounded to rounded and moderately sorted. Intraclasts of argillaceous material and anhydrite are common; they often occur in poorly defined, near-horizontal bands. The rock is well indurated due to anhydrite cementation. Primary matrix material is rare. Primary sedimentary structures generally are absent, but this facies often grades upwards to cross-laminated sandstone. A pseudo-brecciated appearance is common, with minor amounts of finer material interspersed with patches of massive anhydrite-cemented sandstone.

ZONATION AND CORRELATION

A twofold subdivision of the Lower Amaranth is possible, corresponding withthe zonation of the Spearfish strata in North Dakota by Harrison and Larson (1958; Fig. 3), and the recognition of a frosted grain unit and an overlying red silt and shale unit in the Lower Watrous strata of Saskatchewan by Cumming (1956). For the purposes of this discussion, Lower Amaranth strata in the Waskada area have been informally subdivided into a lower sandy unit and an overlying shaly unit as depicted in Figure 3. This subdivision is correlatable regionally and highlights the general fining-upward character of the section.

The lower sandy unit is of most interest, as it includes the reservoir beds of the Waskada pool. A representative lithological section of the lower sandy unit from the Waskada pool, including log plots, is presented in Figure 4.

The sandstone and siltstone lithologies occur in intervals of up to 4 m thick, and are recognizable as "sandy intervals" on logs. A common sequence consists of a massive, medium to coarse-grained sandstone at the base. The underlying bed, commonly a maroon shale, shows evidence of scour; rip-up clasts of this material are present near the base of the sandstone. The sandstone, which may be up to 30 cm thick, grades upward to a medium-grained, cross-laminated sandstone of a similar thickness. The cross-laminations appear to be planar and exhibit dips up to 20°. Small scale variation in grain size is responsible for the laminations. Anhydrite cement commonly is associated with the coarser laminae. The cross-laminated

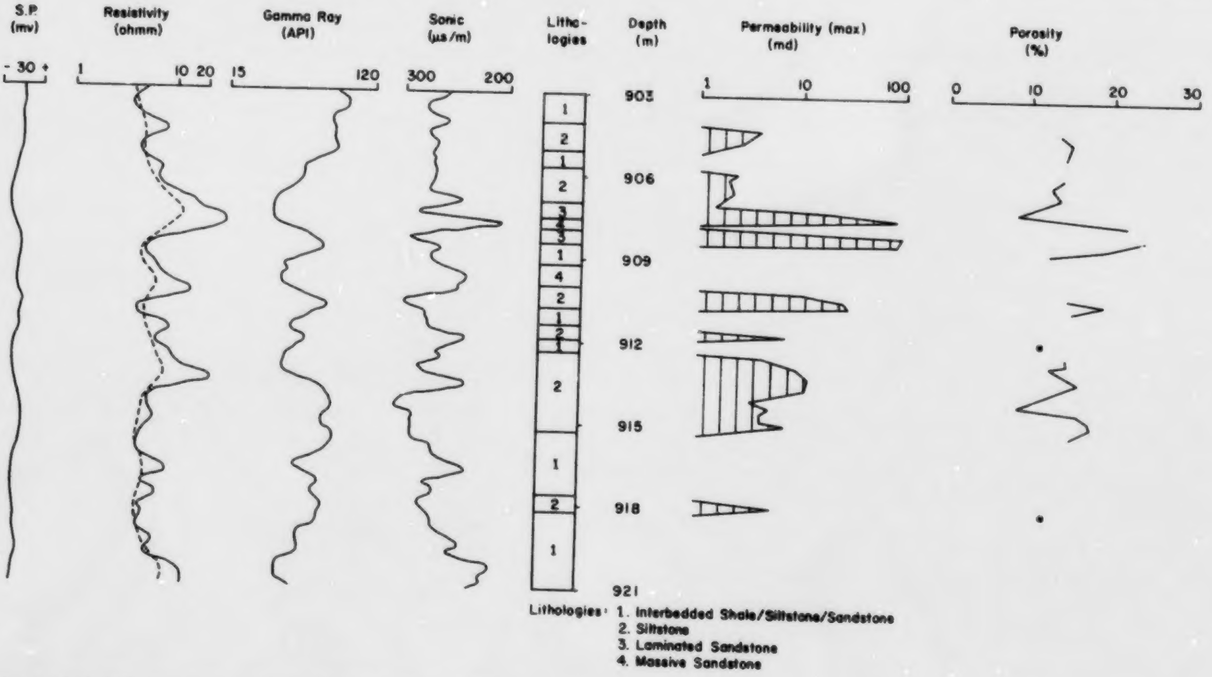

Fig. 4 - Lithology-log reservoir property correlation for 8-26-1-26W1.

sandstone grades upward to a fine to very fine-grained laminated sandstone up to 2 m thick. These sandstones exhibit a variety of sedimentary structures including horizontal lamination, low angle cross-lamination, and small scale current or ripple cross-lamination. This unit usually grades upward to siltstone or interbedded shale and siltstone.

The complete sequence apears to represent a single depositional cycle. Many "sandy intervals" consist of a number of superimposed cycles in which only small parts of individual cycles are represented. The resulting sequence can therefore be complex, but generally it fines upward. Other sandy sequences lack primary sedimentary structures and consist mainly of siltstone. Irregular interbedding with coarser material is common, and contacts with interbedded shales and siltstone are often gradational. Extensive biological or mechanical reworking of this sediment appears to have been responsible for the destruction of primary features.

The correlation of these sandy sequences is based solely on geophysical log characteristics. Core examination reveals that the log-defined correlatable intervals are essentially stratigraphic zones of very complex sandstones and siltstones. The lateral continuity of the individual sandstone beds from well to well may be questionable, but groups of such sequences of the same horizon are correlatable locally and regionally.

DEPOSITIONAL ENVIRONMENT

Regionally, deposition of the Lower Amaranth and its stratigraphic equivalents was associated with a major transgression of Jurassic seas over the northern part of the Williston Basin. The unit is widespread and has a basal onlapping character essentially smoothing over erosional relief on the Paleozoic surface. Given such a setting, the overall environment can be described as transitional, representing the initial stages of a major transgressive event. However, specific despositional environments can range from dominantly continental to marine.

The red colouration of the strata implies oxidization, likely related to periodic wetting and drying of the sediments. Subaerial exposure is supported by the presence of desiccation cracks in some shaly interbeds. The pronounced interbedding of fine and coarser clastics suggests that depositional energy was variable. These variations could be related to fluctuations in water depth or periodic storms. The occurrence of well rounded frosted grains which "float" in a finer matrix indicates eolian deposition. Their abundance suggests periodic emergence whereby eolian deflation and deposition were important processes. The anhydritic nature of the unit relfects evaporitic conditions, possibly associated with periodic emergence of the depositional surface.

The regional presence of the lower sandy sequence and an upper shaly sequence within the Lower Amaranth indicates a change in sedimentation conditions. The lower sandy sequence by nature of its complex lithology, suggests variable depositional conditions. The upper shale sequence indicates more stable conditions as reflected by a more regular lithology with only minor, localized sandstone. The consistency of the stratigraphic section, as reflected by its uniform geophysical log character over the region, is suggestive of a marine-associated depositional environment.

Primary sedimentary structures such as cyclical fining-upward sequences with scour surfaces, rip-up clasts, and large and small scale cross-lamination suggest cyclical variation of depositional energy common in, but not necessarily diagnostic of, fluvial deposits. Significant channels are not evident; it appears that the sands were deposited as thin, laterally-accreted sheets. Whereas lateral continuity of individual fining-upward sequences is limited, gross correlation of stratigraphic zones of this type is possible over considerable distances. These features suggest repeated periods of rapid high-energy deposition, perhaps related to flash-floods during periods of emergence. Mechanical reworking of sediment appears to have been widespread, as evidenced by the abundance of sand and silt which is poorly sorted, commonly structureless or exhibiting only faint, contorted and discontinuous lamination. This pseudo-breccia may have resulted from desiccation and redeposition of a partially indurated laminated or massive sand.

These observations imply a complex and variable depositional environment. Regional continuity of the basic character of the section suggests a marine association. Periodic emergence is evident, indicating terrestrial conditions. An extensive mud flat with playa lakes, eolian deflation and deposition is a possible environmental model. Flash-flooding of the flat with deposition of coarser clastics is suggested by the laminated and cross-laminated sands occurring as thin sheets. Thus these sands may represent poorly developed fluvial systems activated by storms. Alternatively, they may simply reflect marine winnowing of the sediments in shallows by wave action during storms.

Local relief on the sea floor may be attributed to subsidence related to solution of salt beds in the underlying Devonian Prairie Evaporite. Much of the pronounced structural disturbance in the underlying Mississippian strata is attributed to early, repeated salt solution and collapse, and it is quite possible that salt solution during Lower Amaranth time had a significant effect on local depositional patterns. It is noteworthy that the distribution of sandstone in the Waskada area is coincident with a pronounced Mississippian structural anomaly.

In summary, it appears that deposition was most likely related to intermittent shallow marine conditions. Sandy beds may in part represent fluvial deposits on a periodically emergent mud flat. Alternatively, winnowing of sediment by wave action in shallow marine conditions may be the primary depositional mechanism. Regardless, widespread reworking of the sands during the continued transgression is apparent, and this has resulted in sheet like sand bodies.

RESERVOIR CHARACTERISTICS

Reservoir characteristics of Lower Amaranth lithologies are highly variable. Although the entire lower sandy unit may show oil stain, only the more porous sandy beds have sufficient permeability to act as effective reservoirs. The reservoir thus consists of a system of horizontally connected permeable zones within the lower sandy unit.

A fairly consistent relationship exists between reservoir quality and lithology. Most of the net pay is found in the siltstone/sandstone lithology. Porosity is both primary intergranular and secondary intercrystalline in the recrystallized dolomite matrix. Permeabilities to air generally range from 1 to 10 md even though this material appears to be tight. The laminated sandstone lithology exhibits the best reservoir quality with permeabilities of over 100 md in some cases. The massive sandstones are consistently poor in reservoir quality, as virtually all of the primary intergranular pores are filled with

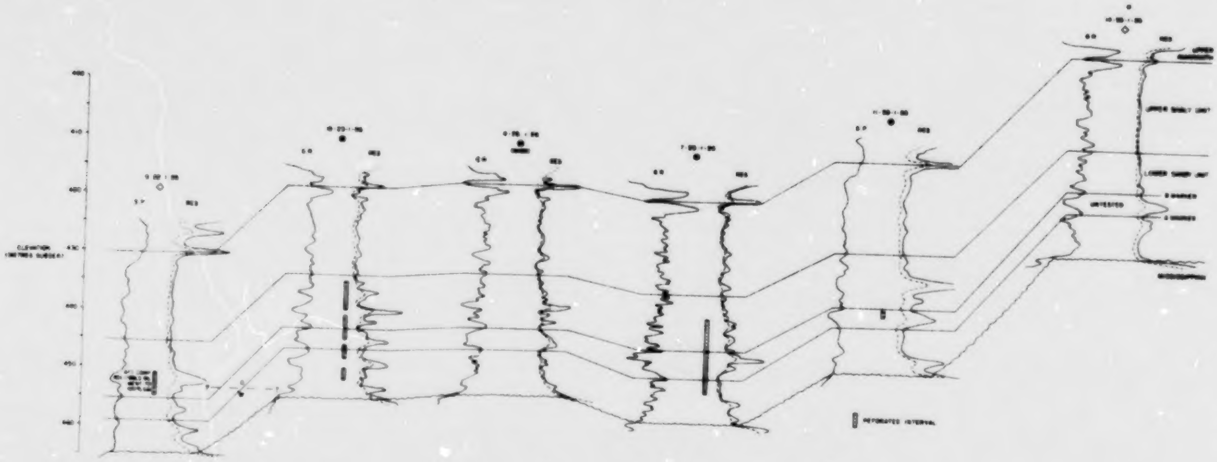

Fig. 5 - Structural cross section of the Waskada Pool.

anhydrite. The interbedded shale/siltstone/sandstone lithology is generally tight. The relationship between lithology, reservoir properties and log responses of the Waskada Lower Amaranth is shown in Figure 4.

Using a permeability threshold of 1 md to define effective pay, a total of 8.2 m of net pay was identified in this section. The average porosity is 14.5% and average permeability is 14.8 md. This section is typical of the Lower Amaranth pay zones found in Sections 25 and 26 of Township 1, Range 26W1. To the south, there is a general decrease in laminated sandstone and most of the pay is found in the siltstone/sandstone. A dip cross-section of the pool is present in Figure 5. The up-dip limits of the pool are controlled by decreasing net pay associated with an as yet undefined permeability barrier. The southern and western limits are defined by an edge-water contact as indicated by log responses of Lower Amaranth sands in the dry holes in the west half of Township 1, Range 26W1 and recovery of salt water on drillstem tests. Given the complex stratification of the reservoir, the oil/water contact also is complex, involving significant transition zones in the low permeability strata.

COMPLETION PRACTICES

Typically, wells are drilled to a total depth of approximately 950 m in order to evaluate both the Lower Amaranth and the underlying Mississippian zones. Lower Amaranth completions involve the perforation of 5 to 10 m of pay through 114 mm production casing. A polyemulsion fracture treatment is then applied using 20 to 30 t of sand fed at pressures from 12 to 24 Mpa. Breakdown is usually achieved at about 16 Mpa. Ball sealers are often used to ensure that the treatment is applied to the entire perforated interval. Some wells will flow for a short period after the fracture treatment, but pump and rods are usually run to place the well on production.

PRODUCTION TRENDS

Table 1 summarizes the production for the Waskada Lower Amaranth Pool from January 1983 to March 1984. It is difficult to draw conclusions on decline trends from this aggregate data, as new wells were continually being drilled and placed on production during this period. Individual well histories vary in both decline rates and water/oil ratios.

In general, production has undergone rapid primary decline due to pressure depletion. In some parts of the field, pressures declined to less than half of the original reservoir pressure in a little over one year of primary production. This performance suggests a low-energy solution gas drive reservoir. For this reason, pressure maintenance through water and gas injection has been instituted throughout most of the field. Response to pressure maintenance has been rapid in most cases, with oil rates increasing and gas/oil ratios decreasing, usually within four months of the start of injection.

Due to the low energy of the reservoir, primary recovery is likely to be low, probably somewhat less than 10% of the oil in place. Early indications are that pressure maintenance will improve recovery, but more production data will be required to evaluate the success of secondary recovery in the pool.

Table 1.
Waskada Lower Amaranth A Pool Production.

Source: Manitoba Department of Energy and Mines, Monthly Production Statistics.

DATE	OIL (M^3)	WATER (M^3)	WOR	WELLS	AVE. RATE (M^3/Day/Well)
1983					
Jan.	10,928	7,500	.69	84	4.2
Feb.	10,208	6,273	.61	88	4.1
Mar.	11,755	6,812	.58	94	4.0
Apr.	12,335	8,071	.65	105	3.9
May	12,788	11,375	.89	105	3.9
June	12,931	10,784	.83	113	3.8
July	15,590	17,256	1.11	130	3.9
Aug.	16,168	19,594	1.21	135	3.9
Sept.	17,102	23,379	1.37	153	3.7
Oct.	18,384	22,816	1.24	165	3.6
Nov.	19,087	23,058	1.21	170	3.7
Dec.	18,550	22,426	1.21	173	3.5
1984					
Jan.	18,290	23,925	1.31	187	3.2
Feb.	17,051	24,064	1.41	199	3.0
Mar.	17,036	25,482	1.50	206	2.7

EXPLORATION PROBLEMS

Exploration for Lower Amaranth oil pools requires identification of favourable reservoir facies occurring in a trap configuration, and identification of an oil source and migration route into such a reservoir. The Waskada pool can be used as a model to identify such targets and apply known concepts to exploration strategy.

Trapping is related to an updip porosity-permeability pinchout. The nature of this pinchout is not well understood, but is likely to be an updip facies change within the strata of the lower sandy unit. Further detailed studies of the sandstones may lead to a predictive model of sandstone distribution and trapping configurations.

Diagenetic facies should also be studied carefully, as porosity may be controlled to a large extent by a diagenetic overprint rather than by primary deposition. Secondary porosity in dolomitic matrix is of particular interest and regional diagenetic patterns would be useful in identifying favourable trends.

Mapping of porosity-peremeability pinchouts combined with structure on Lower Amaranth markers would be useful in identifying potential traps.

The second key problem in Lower Amaranth exploration is the identification of an oil source capable of charging the sandstone reservoirs. A Mississippian oil source is supported by the physical similarities of Lower Amaranth and Mississippian oils. Analysis of samples from the Waskada area indicates similar oil density and sulphur content. Both oils are believed to be the Type II oils (Bakken-Madison Oil System) of Dow (1974).

Assuming a Mississippian source for the oil, a migration path into the Lower Amaranth reservoirs must also be identified. Dow (1974) indentified the Charles salts as barriers to vertical migration of oil from the Madison system. Only beyond the subcrop edge of the Charles salt in North Dakota is there a possibility of vertical migration into post-Mississippian reservoirs. Extensive lateral migraiton of oil has occurred through stratigraphically defined permeable zones in the Mississippian and trapping is common where these zones are truncated at the unconformity. This is the case for most Mississippian reservoirs in Manitoba. However, if the Amaranth section immediately above the unconformity is permeable, oil may migrate into it and gain access to sandstone reservoirs.

The Newburg and South Westhope Spearfish Pools in North Dakota provide evidence of this migration process. The reservoir in these cases actually straddles the unconformity, including both porous Charles strata and the overlying basal sandstone of the Spearfish. Although not directly analogous to Waskada, these pools demonstrate that post-Mississippian strata can be charged with Mississippian oil at the unconformity. This "leakage" effect from underlying Mississippian strata is believed to also apply to the Waskada Pool.

Given this type of migration path, it is possible to identify areas where the Lower Amaranth may have been charged with Mississippian oil on the basis of the stratal types at the Mississippian subcrop surface. Intersections of the major zones of permeability define potential infiltration areas. The subcrop of the permeable MC3 member of the Mission Canyon Formation is of particular interest, as the permeable zones are regionally extensive and serve as significant carrier beds as well as reservoir beds in the Pierson and Waskada Fields. A schematic diagram of such a migration path is presented in Figure 6.

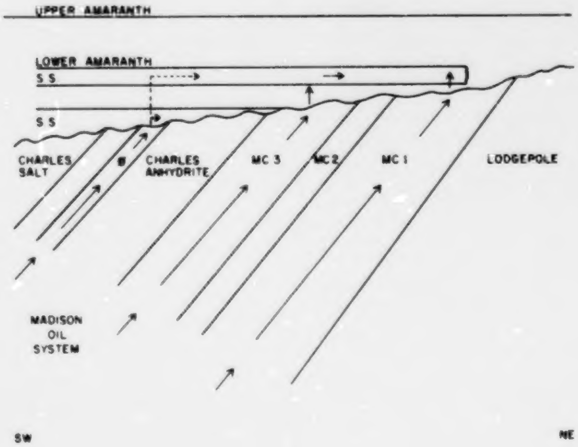

Fig. 6 - Schematic migration route of oil from Mississippian strata into the Lower Amaranth.

Given the generally low permeability of most of the basal part of the Amaranth, transfer of oil through it into the more permeable sandstones presents a problem. The main MC3 subcrop belt rises structurally to the southeast. Given the relative permeabilities of the MC3 and Lower Amaranth, the tendency would be for oil to migrate in the direction of greatest permeability, which would be along the subcrop belt. Trapping in the MC3 occurs coincidentally with facies changes in the MC3, with paleotopographic relief, or with pre-erosional Mississippian structure. The Mission Canyon oil pools at Pierson and Waskada are examples of such situations. However, the development of an oil column in the Mission Canyon at any point in time is probably instrumental in initiating transfer of oil into the Lower Amaranth. A certain minimum height may be required to generate the threshold buoyancy pressure required to force oil into relatively impermeable strata of the Lower Amaranth. Capillary pressure properties of the rocks involved would determine quantitatively how this process might have occurred. Such data are not presently available; a schematic representation of the situation is presented in Figure 7. The Lower Amaranth acts as a seal until the oil column reaches height H. At this point, buoyancy pressure would be sufficient to cause the seal to "leak", and oil to enter the sandstone reservoirs.

Capillary pressure properties are a function of lithology and therefore are quite variable across the Mississippian-Lower Amaranth interface. Points of entry of Mississippian oil into the Lower Amaranth are probably sporadic, depending on the presence or past presence of Mississippian oil columns as well as relative permeabilities of the lithologies involved. A tight dolomitized and anhydrite infilled zone of variable thickness below the unconformity surfaces as well as vertical fracture systems related to salt collapse complicate the situation.

There appears to be an intimate association between Mississippian and Lower Amaranth pools. This association could provide a useful exploration tool: it is clear that an intergrated approach to Lower Amaranth and Mississippian ex-

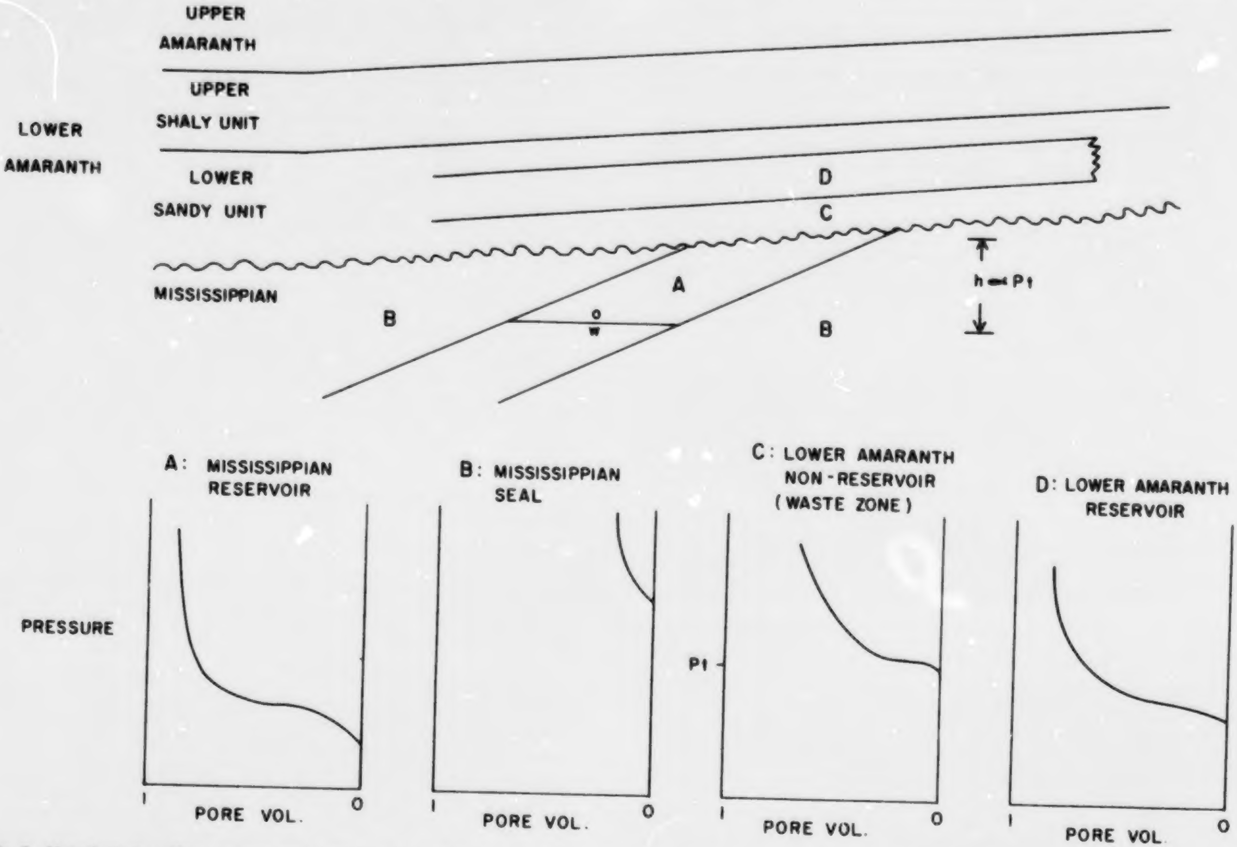

Fig. 7 - Hypothetical capillary pressure curves showing the hydrodynamic relationships necessary for leakage of oil into the Lower Amaranth.

ploration is required. A Mississippian pool occurring below favourable reservoir facies in the Lower Amaranth indicates a Lower Amaranth prospect. The precise location depends on the extent of updip lateral migration in the sands until a trap is encountered. Even a show of oil in a wet Mississippian zone is significant, in that it may be indicative of a site where leaking of oil into the Lower Amaranth has occurred. Conversely, Lower Amaranth oil pools and shows may indicate Mississippian pools, most likely downdip.

The extent of lateral oil migration within the Lower Amaranth is an important consideration. If the permeable zones are limited laterally, migration would be limited and trapping will occur in proximity to the area where oil has gained access to the Lower Amaranth. If lateral continuity of the permeable zones is good, exploration should concentrate on the regional porosity-permeability pinchout trends in the Lower Amaranth.

The Waskada Lower Amaranth Pool provides an excellent example of how these interrelated exploration concepts apply to a commercial reservoir. Figure 8 is a schematic cross section of the Waskada area. The trap is provided by the porosity-permeability pinchout to the north and east. Porous Mississippian strata subcrop in the area and, more importantly, numerous Mississippian traps with associated oil columns are present. This provides several potential migration routes into the Lower Amaranth.

CONCLUSIONS

The existence of the Waskada Lower Amaranth Pool in southwestern Manitoba has important implication for oil exploration in southeastern Saskatchewan. The general geological setting of Waskada persists over most of southeastern Saskatchewan, making it a good hunting ground for Waskada-type Spearfish pools. The Waskada Pool provides a model for identification of the key exploration problems.

The intimate association between Mississippian and Lower Amaranth pools can be used as a powerful exploration tool and stresses the need for an integrated exploration approach. An understanding of the physics of fluid movement is required to evaluate potential migration routes in the Mississippian and the significance of oil shows either below or above the unconformity.

The experience at Waskada shows that the concepts of "reservoir" and "seal" cannot be regarded as absolutes. The flow of fluids is governed by hydrodynamic principles related to the leakage and migration of oil beyond what are regarded as conventional unconformity truncation traps.

The Waskada Lower Amaranth Pool was repeatedly drilled through without being recognized as a potentially productive zone for 25 years prior to its "discovery" in 1980. This suggests that exploration for similar pools should start by evaluating existing wells in a comparable geological setting in

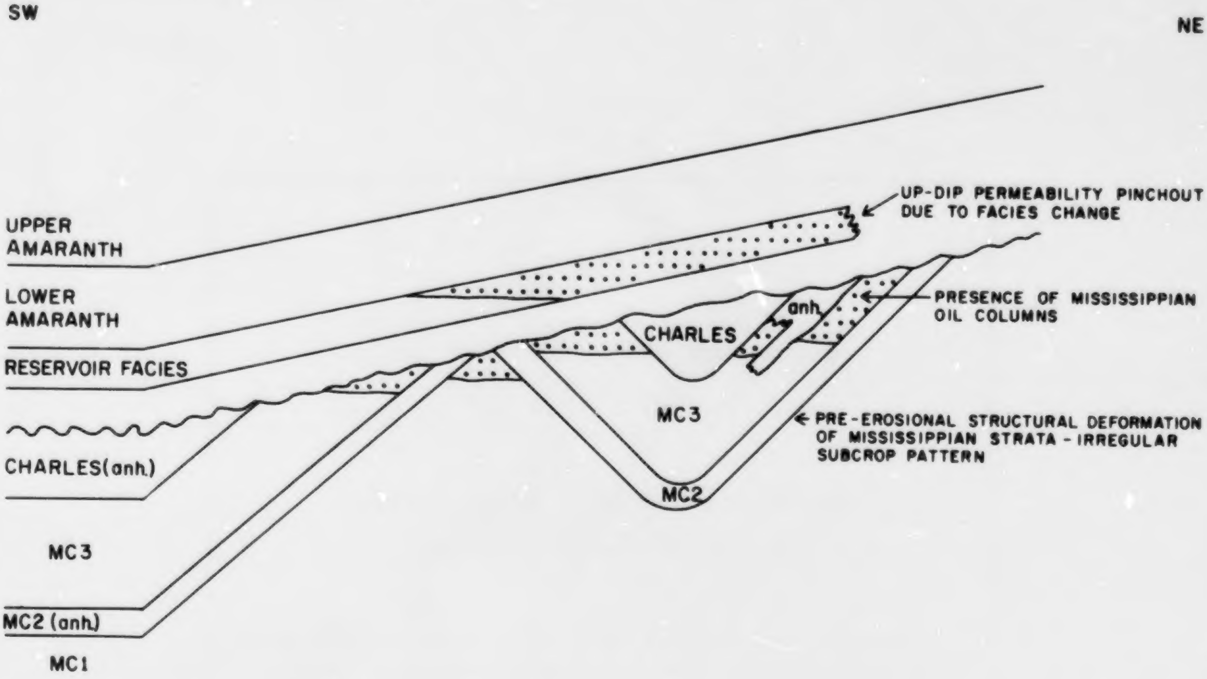
SW
NE
UPPER AMARANTH
LOWER AMARANTH
RESERVOIR FACIES
CHARLES(anh.)
MC3
MC2 (anh.)
MC1
CHARLES
anh.
MC3
MC2
UP-DIP PERMEABILITY PINCHOUT DUE TO FACIES CHANGE
PRESENCE OF MISSISSIPPIAN OIL COLUMNS
PRE-EROSIONAL STRUCTURAL DEFORMATION OF MISSISSIPPIAN STRATA - IRREGULAR SUBCROP PATTERN

Fig. 8 - Schematic cross section of the Waskada Field, showing relationships between Lower Amaranth and Mission canyon pools.

search of missed pay. Virtually all of the productive trends of southeastern Saskatchewan offer opportunities for such evaluations.

ACKNOWLEDGEMENTS

This paper is essentially a condensation and update of Manitoba Department of Energy and Mines Geological Report GR 82-6 by Barchyn, 1982, which was prepared while the author was employed as the Senior Petroleum Geologist, Petroleum Branch, Manitoba Department of Energy and Mines. The support of the Department is herewith acknowledged.

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SOURCE OF OILS IN CRETACEOUS FIELDS OF SOUTHERN SASKATCHEWAN[1]

DONALD G. VAN DELINDER[2]

[1]By permission, Dr. C. Evans, Imperial Oil Ltd., Calgary, Alberta.
[2]Van Delinder, Donald G., President of Geochem Laboratories Ltd., Calgary, Alberta.

INTRODUCTION

The Cretaceous oil pools in southern Saskatchewan on the north flank of the Williston Basin were not sourced from Cretaceous beds, but rather, represent migration from older reservoirs.

WAPELLA FIELD AREA — SOUTHEASTERN SASKATCHEWAN

At the Wapella Field (Figs. 1 and 2), the Cretaceous oil pools appear to represent Mississippian crude oil which has migrated up a fracture-fault and fed, bed by bed, several thin Jurassic and Lower Cretaceous Mannville sands. This interpretation is based on the distribution of oil shows within the Lower Cretaceous and Jurassic units of the general area, and a similarity of the Wapella crude oil to local Mississippian crude oils in C^{13}/C^{12} carbon isotopic composition.

The pattern of oil shows within the Cretaceous Mannville, and the Jurassic formations in southeastern Saskatchewan is shown in Figure 3. Wapella was the first oil discovery in southeastern Saskatchewan, but to this date stands alone as the only oil pool within either Cretaceous- or Jurassic-age beds in a radius of over 300 km.

The areal distribution of oil shows in the Jurassic and Watrous (red bed) sequence suggests a local source for the Wapella crude oil, in that these formations are adjacent to the field.

The Wapella crude oil is similar in C^{13}/C^{12} carbon ratio to the oils present in the Mississippian Mission Canyon reservoirs at the Parkman and Alida Fields, and the Lodgepole Formation at the Ebor Field (Fig. 4). A plot of these C^{13}/C^{12} ratios (relative to the PD standard used by the U.S. Petroleum Industry) from the $C_{15}+$ paraffin-napthene fractions of the oils shows this similarity, and lends support to the hypothesis of a Mississippian source.

Structure contours on the Jurassic Watrous Formation indicate the Wapella Field to be close to a north-south zone of flexures which may have served as a migration path. This zone may represent a tensional fracture system with probably dies out within the thick Cretaceous shale above the Mannville.

FORSTERTON-CANTUAR-SUCCESS AREA —SOUTHWESTERN SASKATCHEWAN

The crude oil found in the Cretaceous pools at Fosteron, Cantuar, Success, and Battrum, (Fig. 1) are believed to represent oil that has migrated from Jurassic source beds.

The following genetic history (Fig. 5) is postulated:

- migration from the productive Jurassic Upper Shaunavon sand trend to the subcrop at the Pre-Cretaceous (?) Unconformity;
- movement of this oil through a valley sand (of Lower Cretaceous or Upper Jurassic age) into the erosional escarpment of the Jurassic Middle Vanguard sand, and eventually;
- transfer of this oil into the basal Cretaceous Cantuar sand where permeable, and where it is in erosional contact with the Middle Vanguard sand.

The Jurassic Upper Shaunavon porous sand unit (Fig. 6) appears to be an "oily" unit over a very broad area of southwestern Saskatchewan, northern Montana, and southern Alberta. It is productive at a number of localities including the Delta, Bone Creek, and Dollard Fields of southwestern Saskatchewan, and the Bowes Field in northern Montana. Near the Sweetgrass Hills in northwestern Montana, and in southern Alberta, several gas pools also occur.

It is inferred that oil could have escaped from the Shaunavon sand at three of its subcrops at the Pre-Cretaceous (?) Unconformity. Two of these localities are near the Fosterton-Cantuar-Success Fields, where a porous sand, deposited in valleys cut into porous Upper Shaunavon sand, provides an apparent permeability link between the Upper Shaunavon sand and the Middle Vanguard sand. Porous Middle Vanguard sand, into which these valleys were carved, is assumed to have been a source of the valley sand bodies. Oil shows have been recorded from the valley sand, but no production.

The Middle Vanguard sand, which along with the Upper Shaunavon contains the bulk of the proven oil reserves of southwestern Saskatchewan, has an oil show area (Fig. 7) which spreads out from the erosional edge of this fairly continous porous sand unit. The author believes that this oil show area reflects the encroachment of Upper Shaunavon oil into this sand unit vai the connecting valley sands. There are no recorded oil shows in the area to the east and southeast of the oil show area. The updip shaleout of this sand south of the oil show area, and away from the assumed points of origin of the incoming oil, is also nonproductive.

The Basal Mannville unit, occurring immediately below the Cantuar marker, exhibits an oil show area which lies within the general outline of oil shows of the underlying Middle Vanguard. Within this area, porous sands of the Basal Mannville make local contact with the Middle Vanguard sand where erosion has stripped off the intervening Upper Vanguard shale.

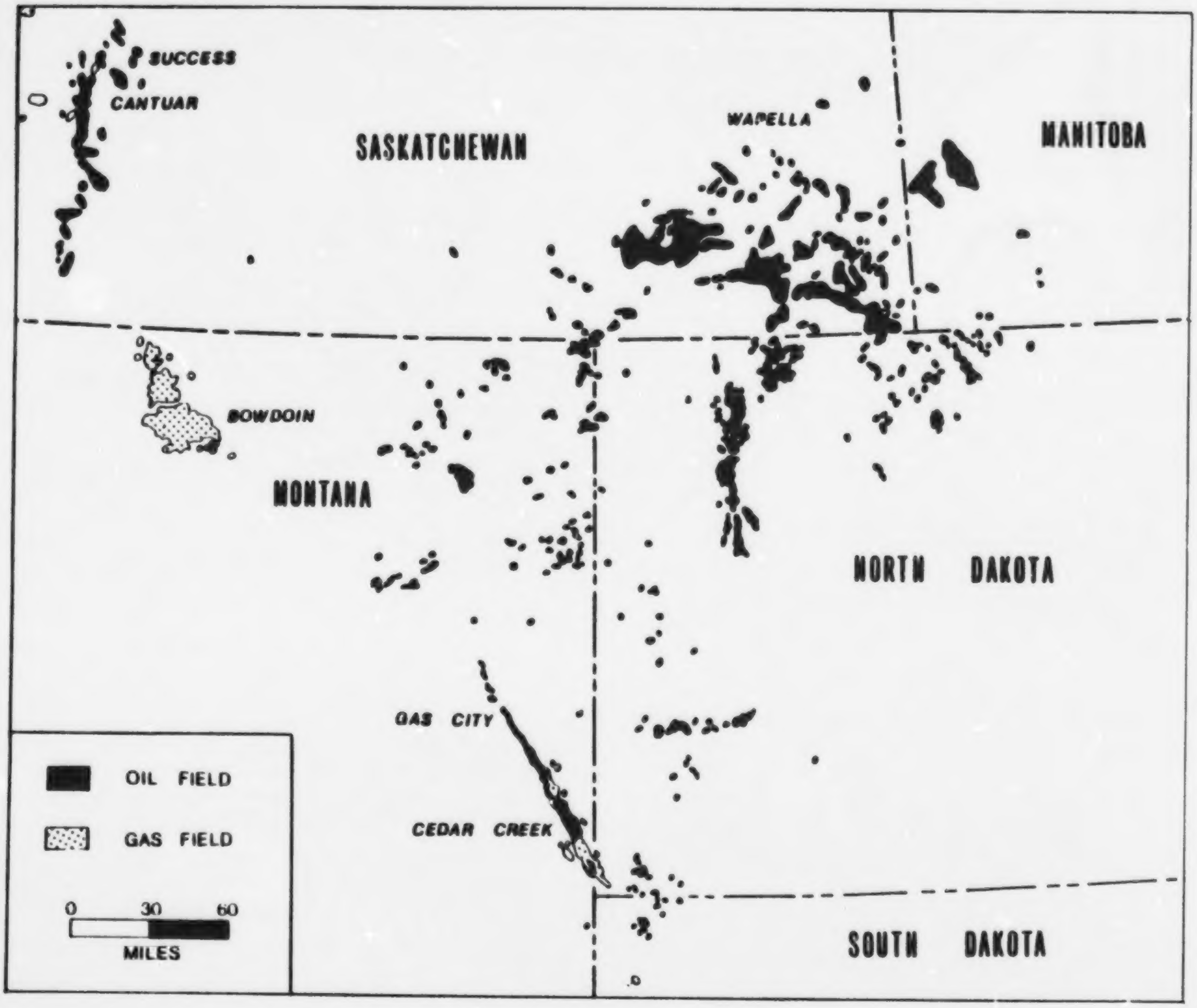

Fig. 1 - Oil and Gas Fields of the Williston Basin

The third locality of oil escape from the Shaunavon is in the northwest sector of the map area. There is, however, no production.

The Upper Mannville sands have virtually no oil shows or oil production anywhere within the study area. These sands are separated vertically from the Basal Mannville sand by a thin, but persistent, impervious zone over the entire study area; this zone forms a barrier to upward movement of oil from the Basal Mannville sands.

The hypothesis of oil migration is conditional on an interconnection of the Upper Shaunavon sand with the Middle Vanguard sand through the valley sand.

There is fluid pressure evidence (Fig. 8) which indicates intercommunication between these three sand units. A drop in the piezometric (potential energy) elevation from the southwest corner of Saskatchewan northeastwards towards the Upper Shaunavon subcrop area indicates water movement in this direction. A continued drop in piezometric elevation within the valley sand, and the Middle Vanguard sand, indicates present-day fluid flow from the Upper Shaunavon into the valley sand and into the Middle Vanguard sand. This fluid flow path is the one postulated for oil migration of the geological past.

CONCLUDING REMARKS

Oil operators wishing to undertake studies of the origin of reservoired crude oils in an area of interest, at this point in time, are best advised to take a more sophisticated and conclusive study approach involving comprehensive hydrocarbon source rock evaluation and crude oil-parent rock service technology currently available to petroleum explorations.

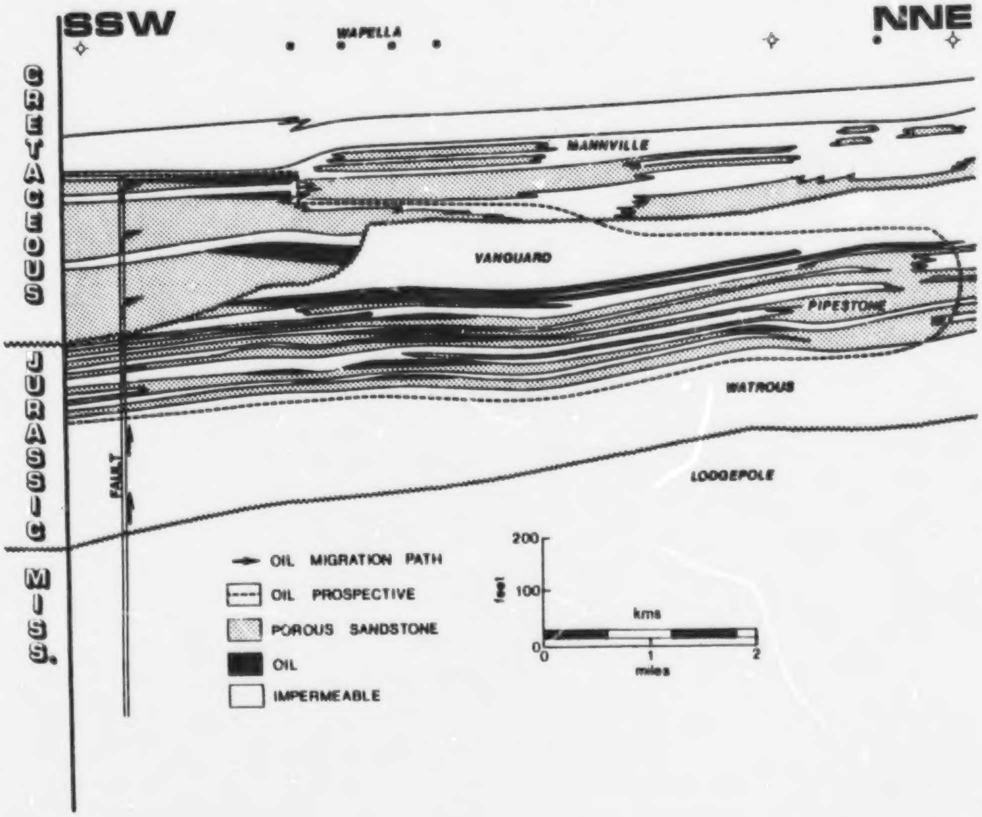
SSW
WAPELLA
NNE
CRETACEOUS
JURASSIC
MISS.
MANNVILLE
VANGUARD
PIPESTONE
WATROUS
LODGEPOLE
FAULT
OIL MIGRATION PATH
OIL PROSPECTIVE
POROUS SANDSTONE
OIL
IMPERMEABLE
200
100
0
feet
kms
0
1
2
miles

Fig. 2 - Secondary Oil Migration: Wappella Field, S. E. Saskatchewan

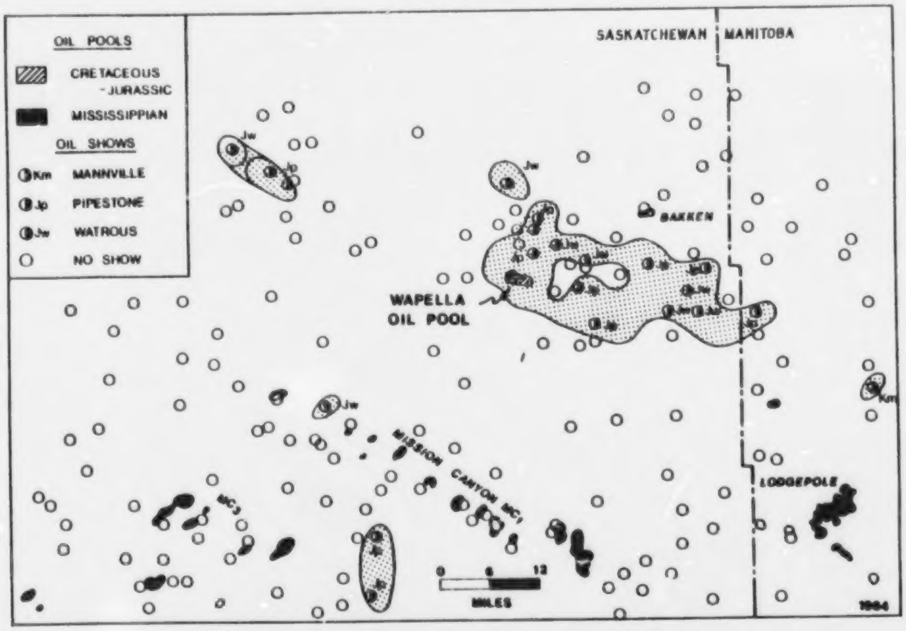
OIL POOLS
CRETACEOUS - JURASSIC
MISSISSIPPIAN
OIL SHOWS
Km MANNVILLE
Jp PIPESTONE
Jw WATROUS
NO SHOW
SASKATCHEWAN
MANITOBA
Jw
Jp
Km
BAKKEN
WAPELLA OIL POOL
MISSION CANYON MC1
MC3
LODGEPOLE
0
6
12
MILES
1984

Fig. 3 - Cretaceous and Jurassic Oil Shows - Wapella Area

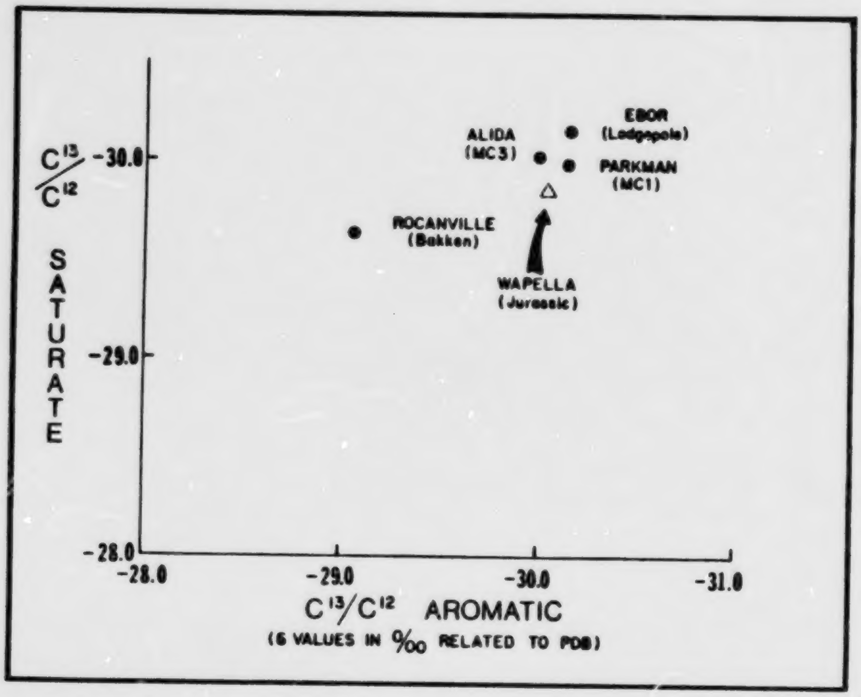

Fig. 4 - Comparison of C^{13}/C^{12} Carbon Isotopic Composition - Wapella Jurassic Oil vs. Local Mississippian Crudes

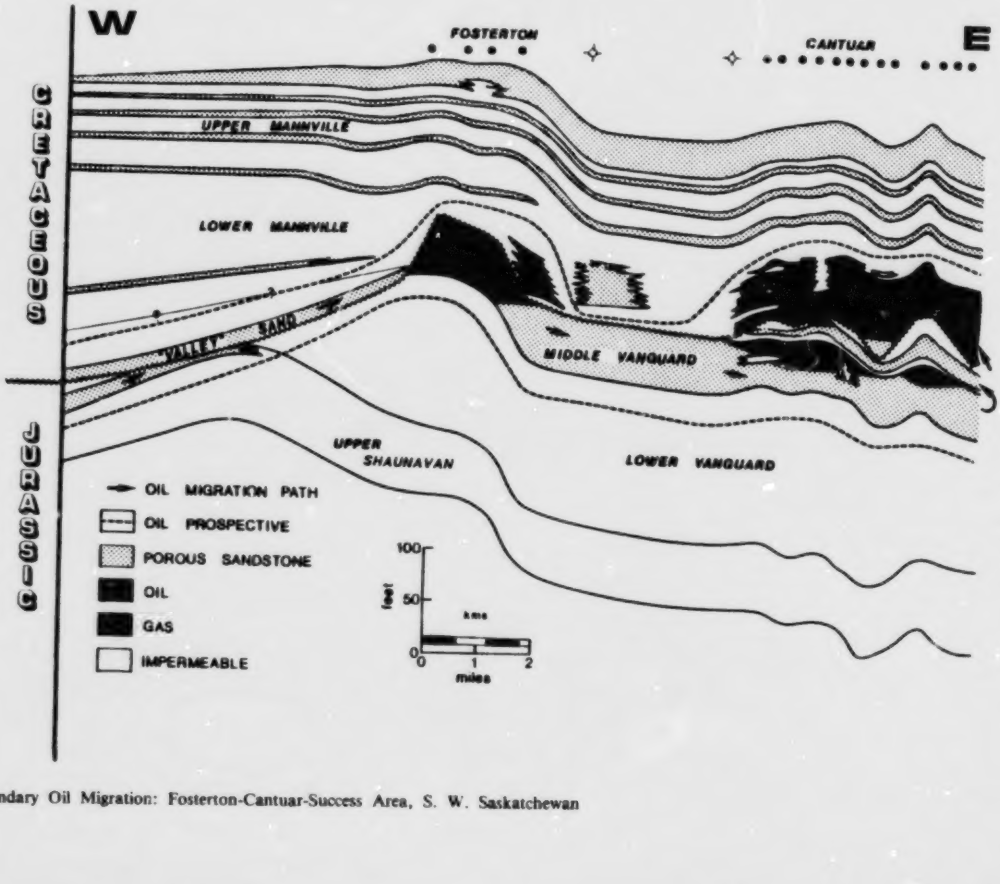
W
E
FOSTERTON
CANTUAR
CRETACEOUS
JURASSIC
UPPER MANNVILLE
LOWER MANNVILLE
"VALLEY" SAND
MIDDLE VANGUARD
UPPER SHAUNAVAN
LOWER VANGUARD
OIL MIGRATION PATH
OIL PROSPECTIVE
POROUS SANDSTONE
OIL
GAS
IMPERMEABLE
100
50
0
feet
kms
0
1
2
miles

Fig. 5 - Secondary Oil Migration: Fosterton-Cantuar-Success Area, S. W. Saskatchewan

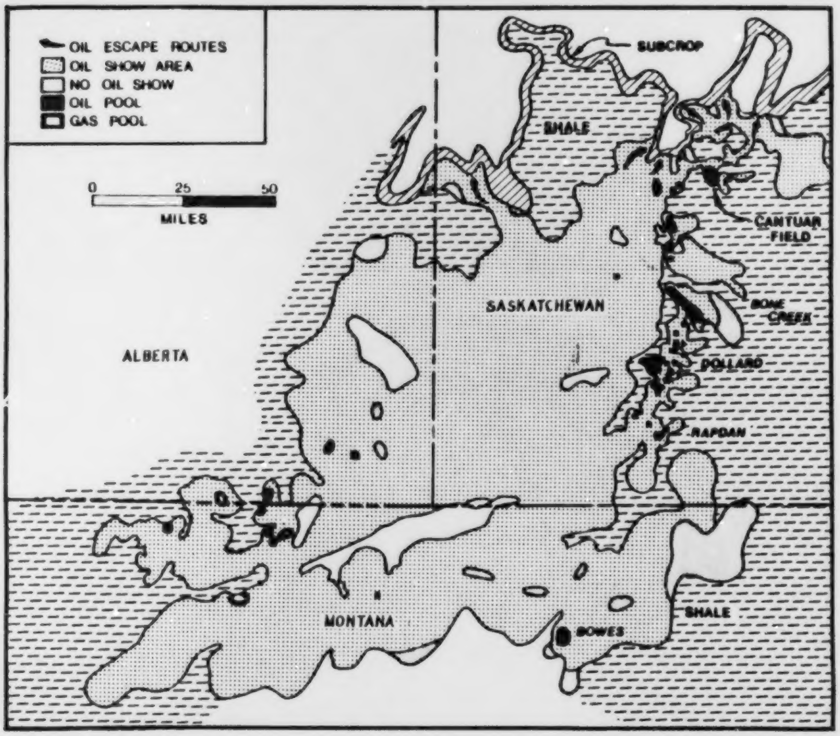
OIL ESCAPE ROUTES
OIL SHOW AREA
NO OIL SHOW
OIL POOL
GAS POOL
0
25
50
MILES
SUBCROP
SHALE
CANTUAR FIELD
BONE CREEK
DOLLARD
RAPDAN
SASKATCHEWAN
ALBERTA
MONTANA
BOWES
SHALE

Fig. 6 - Oil Show Distribution - Upper Shaunavon Sand

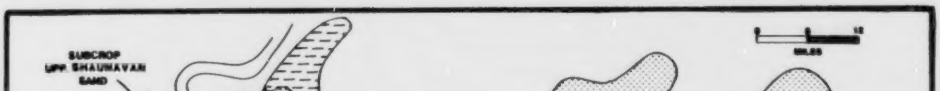
SUBCROP
UPP. SHAUNAVAN SAND
OIL MIGRATION VIA "VALLEY SAND"
FOSTERTON
CANTUAR
"OIL - PRONE"
B
1100
1200
"BARREN"
SHALE
OIL MIGRATION PATH
GAS POOL
OIL POOL
BARREN TRAP
N
1962

Fig. 7 - Oil Show Distribution - Middle Vanguard Sand

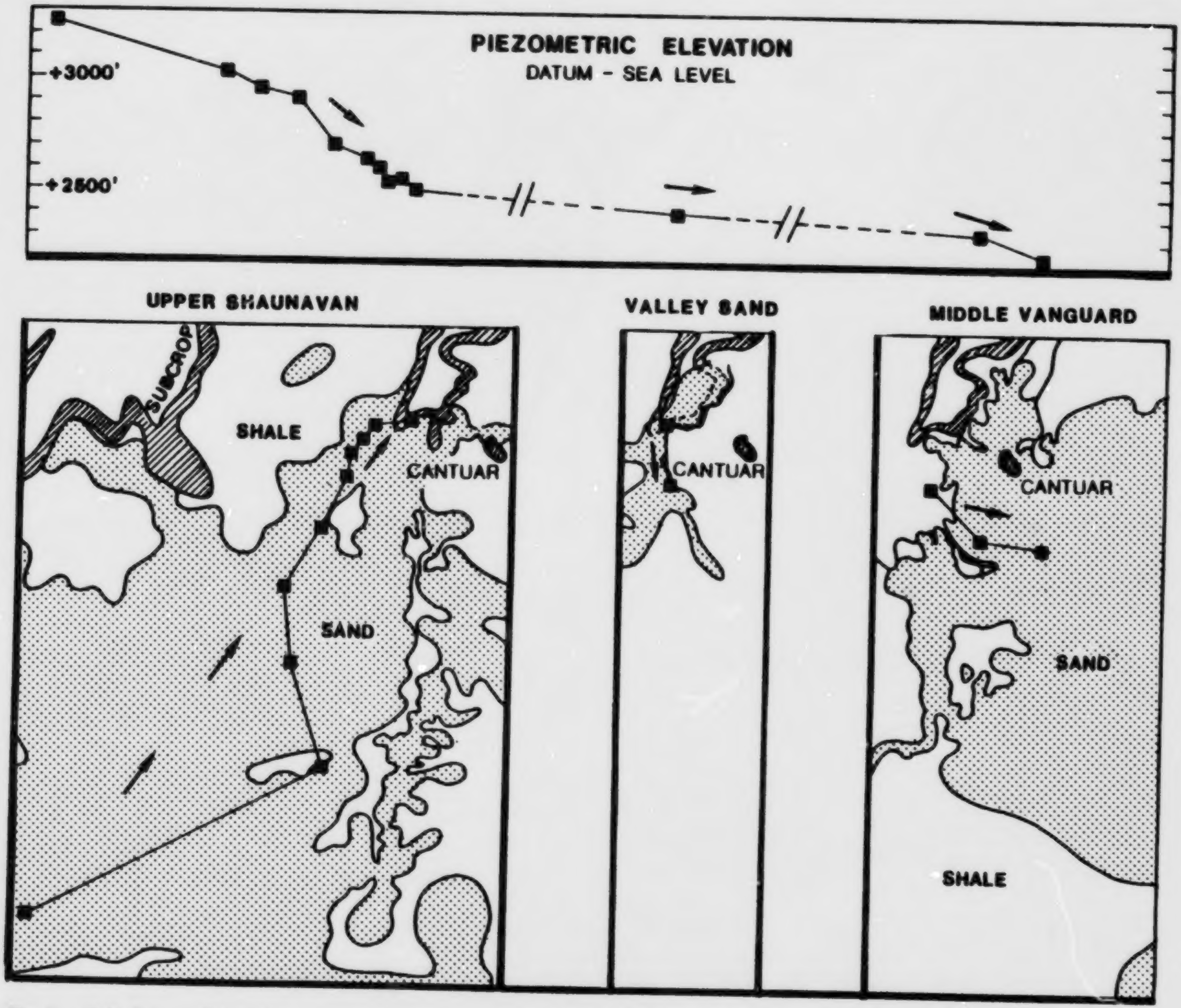
PIEZOMETRIC ELEVATION
DATUM - SEA LEVEL
+3000'
+2500'
UPPER SHAUNAVAN
VALLEY SAND
MIDDLE VANGUARD
SUBCROP
SHALE
CANTUAR
SAND
CANTUAR
CANTUAR
SAND
SHALE

Fig. 8 - Fluid Pressure Distribution - Upper Shaunavon Sand/'Valley' Sand/Middle Vanguard Sand

DEPOSITIONAL ENVIRONMENTS OF THE MANNVILLE GROUP (LOWER CRETACEOUS) IN THE TANGLEFLAGS AREA, SASKATCHEWAN

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Saskatchewan Geological Survey
201 Dewdney Avenue East
Regina, Saskatchewan S4N 4G3

ABSTRACT

Sedimentation of the Mannville Group in the area of Tangleflags Field was dominated by a succession of transgressive-regressive marine pulses. Sea level changes were, in turn, controlled by the interaction of basin subsidence, sediment influx and, probably, the effects of salt solution.

A detailed examination of cores in and around the Tangleflags Field indicates three main depositional environments; nearshore (characterised by swash-zone cross lamination), tidal (pin-stripe bedding, interlaminated silts and shales), and coastal swamp (carbonaceous shales, root zones, and coals). In the Tangleflags North Field, well developed "channel" sediments (fining-up sequences) are an anomalous feature. With the present well control it has not been possible to outline the limits of this feature.

The basic pattern of transgressive-regressive marine pulses has been influenced by minor tectonic warping associated with subsidence of the Western Canada Basin and/or local salt tectonism. There is clear evidence for structural activity both during and after Mannville time. Although they did not radically alter the pattern of Mannville sedimentation, tectonic events led to thinning and draping of sediments over local structural highs. Lithological sequences suggest that the structural highs were emergent more often and/or for longer periods than adjacent lows.

Farther east, in the area of Celtic Field, excellent core control shows a similar vertical sedimentary sequence to Tangleflags. In Celtic, however, the sediments show more marine and less terrestrial influence (*cf.* Lorsong, 1980).

INTRODUCTION

This study is based on information obtained from approximately 1100 wells drilled into, or through, the sediments of the Mannville Group in an area north and east of Lloydminster (Fig. 1). The area outlined covers some 1990 km^2 (768 mi^2) and includes a number of heavy oil and gas pools. Cores of the Mannville were cut in 73 wells; all were examined to provide basic sedimentologic information. The majority of the data for maps and cross-sections have been obtained from resistivity and spontaneous potential logs, with additional information obtained from other logs where available.

The Lloydminster area contains extremely large reserves of heavy oil. It is believed that the only way to recover a significant proportion of the oil is to reduce its *in situ* viscosity via enhanced recovery processes. Before complex and expensive enhanced recovery processes can begin, it is necessary to the thoroughly understand the physical and chemical properties of the reservoir sands. The purpose of this paper is to paint a clearer picture of the deposition of Mannville sediments within the study area and, also, to show how sedimentation patterns have been affected by syndepositional and postdepositional tectonic processes. This study is intended to provide a fundamental framework within which physical and chemical properties of reservoir strata can be better understood. Further work in the Lloydminster area will, it is hoped, show the relevance of this study to other areas and further refine the interpretations made here.

STRATIGRAPHY

The Mannville Group, originally the Mannville Formation, was defined by Nauss (1945) from the Northwest Mannville Well No. 1 (1-18-50-8W4) in Alberta and subsequently raised to group status by Badgley (1952) and Glaister (1959). Whilst the limits of the Mannville itself are clearly defined, the difficulties inherent in subdivision of the Mannville have created many stratigraphic problems and led to numerous discrepancies among published works.

The subdivisions of the Mannville used in Saskatchewan (Fig. 2) have evolved from the names given by drillers to the sands encountered in drilling. This evolution of terminology results in the nine subdivisions documented by Vigrass (1977) and Orr *et al.* (1977). It is important to note that the upper seven subdivisions (Lloydminster to Colony inclusive) are only informal units. For the purposes of this paper the following premises will be adhered to:

a) The Colony unit within the Lloydminster area is considered to be the uppermost subdivision of the Mannville Group overlain by the shales of the Joli Fou Formation (with or without the Spinney Hill sands).

b) The Mannville Group will be divided into nine units (Fig. 2) and these units will be referred to by name only with no stratigraphic status implied. Only the Dina and Cummings can be considered as formal units and these have member status (Nauss, 1945).

The stratigraphic scheme used in this study follows the format set out by Vigrass (1977) insofar as it relates to the Tangleflags area. Vigrass considers each subdivision of the Mannville as a sand unit with a subjacent shale, but he believes that there is a hiatus at the top of the shale which overlies the Sparky sand and hence makes it the upper boundary of the Sparky. There is an almost ubiquitous coal seam at the top of the Sparky and the author concurs with early workers, such as Ambler (1950), that the top of this coal is the best pick for the top of the Sparky. In addition, the Waseca itself is more than just a single sand/shale couplet. In the Tangleflags area, the unit falling between the McLaren and the Sparky coal is commonly two, and in some instances three, sand/shale couplets.

In the Tangleflags area oil is produced from the Lloydminster and younger units; consequently, few wells penetrate deeper than the middle of the Cummings. This results in rather sparse information on the lower Cummings, Dina, and the Paleozoic erosion surface.

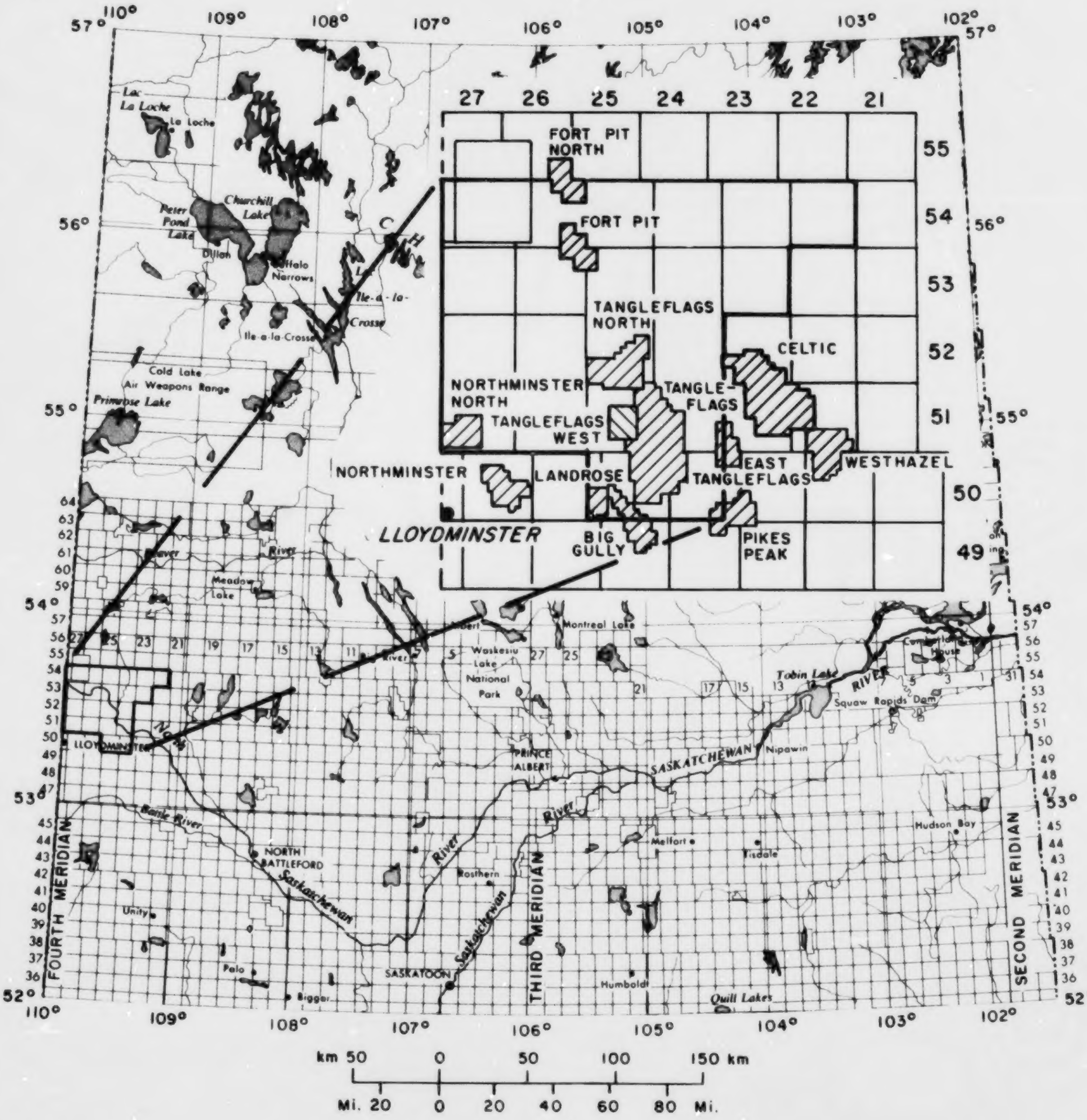

FORT PIT NORTH
FORT PIT
TANGLEFLAGS NORTH
CELTIC
NORTHMINSTER NORTH
TANGLEFLAGS WEST
TANGLE-FLAGS
NORTHMINSTER
LANDROSE
EAST TANGLEFLAGS
WESTHAZEL
LLOYDMINSTER
BIG GULLY
PIKES PEAK
27 26 25 24 23 22 21
55 54 53 52 51 50 49
Lac La Loche
La Loche
Peter Pond Lake
Churchill Lake
Dillon
Buffalo Narrows
Ile-a-la-Crosse
Cold Lake Air Weapons Range
Primrose Lake
Meadow Lake
Montreal Lake
Waskesiu Lake
National Park
Tobin Lake
Squaw Rapids Dam
Cumberland House
Nipawin
PRINCE ALBERT
SASKATCHEWAN RIVER
Battle River
NORTH BATTLEFORD
Saskatchewan
Unity
Rosthern
Melfort
Tisdale
Hudson Bay
Humboldt
Quill Lakes
SASKATOON
Biggar
FOURTH MERIDIAN
THIRD MERIDIAN
SECOND MERIDIAN
110° 109° 108° 107° 106° 105° 104° 103° 102°
57° 56° 55° 54° 53° 52°
km 50 0 50 100 150 km
Mi. 20 0 20 40 60 80 Mi.

Fig. 1 - Location map.

The following is a generalized lithologic description of the units making up the Mannville Group in the Tangleflags area:

Colony Commonly composed of interbedded sands and shales, and overall a rather shaly unit. There may be one or more thin coals present. The sands are fine grained (generally silt to very fine sand). The thickness of the unit is quite variable, but is commonly less than 10m.

McLaren Typically thin (10m or so), showing a coarsening upward response on spontaneous potential and gamma ray logs. In core, a gradation from shales at the base to interbedded sands and shales, to sands at the top is generally visible. The McLaren may be capped with a coal, or coaly shale, which provides a convenient marker when it can be recognised on logs.

Waseca A highly variable unit between the Sparky coal and basal McLaren shale. Typically, the Waseca is about 30 m thick. Unfortunately, this unit is of limited economic significance in the Tangleflags area, resulting in rather sparse

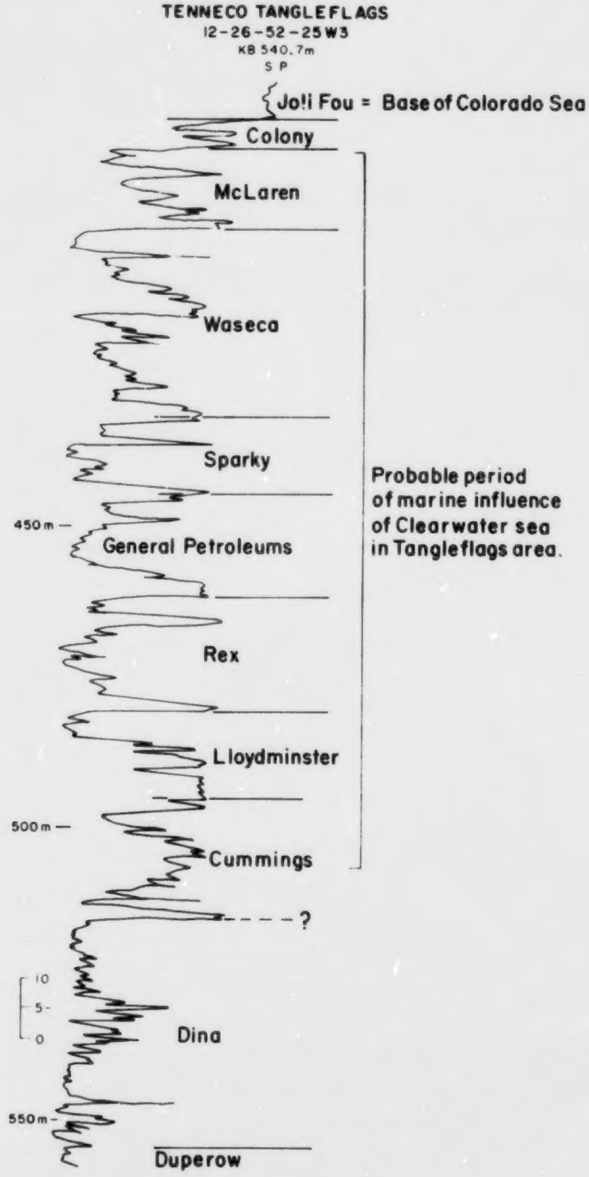


Fig. 2 - Typical spontaneous potential log of the Mannville Group in the Tangleflags area.

core information. Log interpretation suggests several sands separated by shaly intervals. The Waseca may have as many as three, and commonly two, well defined coarsening upward sequences. Commonly, there is a calcite cemented sand close to the base and a coal with a thin overlying sand at the top of the Waseca.

Sparky A sand over shale unit ranging from 10 to 20m in thickness. At the top of the Sparky is a coal which appears to be continuous throughout most of the Tangleflags area (indeed, this coal is common throughout much of the Lloydminster heavy oil district). The coal, because of lateral continuity and ease of recognition, is taken as the top of the Sparky by the majority of Mannville workers and provides a boundary marker preferable to that proposed by Vigrass (1977).

General Petroleums A sandy unit of variable thickness (12 to 20 m) overlying a well-defined shale which forms the base of the unit. Whilst the Sparky and G.P. units are individually quite variable in thickness, their combined thickness is relatively consistent (about 30 m) throughout the Tangleflags area; this suggests that these units would be better combined into one for correlation purposes.

Rex A unit of little economic interest in the Tangleflags area. Typically the Rex is sandy with a coal close to the top, a calcite cemented sand near the base, and a relatively well-defined shale forming the base of the unit. The thickness of this unit is fairly consistent at approximately 20 m.

Lloydminster Usually a well defined coarsening upward sequence on logs and in core. The sand thickness varies from 1-6 m in the majority of wells. The Lloydminster sand is one of the prime economic targets in the area and appears to be laterally the most persistent sand. The sand is commonly overlain by a thin coal.

Cummings Since there is no oil to be found in the Cummings in much of the Tangleflags area, there is a paucity of information on what can be considered as a "normal" Cummings. It appears to be a unit of variable thickness with a sand at the top, shale in the middle and sand near the base, resulting in a bilobate log signature. The basal shale separating the lower Cummings sand from that of the Dina is highly variable in thickness.

Dina Almost always a sandy unit with or without thin shale beds. The thickness of the Dina varies considerably; it is thin or absent in some areas.

Paleozoic Throughout most of the area the Dina rests unconformably on the carbonates of the Devonian Duperow Formation. The boundary is clearly defined on logs and in core as a change from clastics to carbonates. In the one core where this contact is clearly visible (Fig. 3), the weathered surface is relatively thin (approx. 1m).

Petrology

A variety of samples, with a bias toward porous and permeable sands, were studied in thin section. Reservoir sands could not be studied directly because samples must be free of oil for cutting and impregnation; reservoir sands were studied indirectly via samples most like reservoir sands in general appearance. In virtually all cases the sands are dominated by quartz. The quartz is present as monocrystalline quartz, polycrystalline quartz, and chert. Some of the monocrystalline quartz displays strain as undulose extinction. Whilst monocrystalline quartz forms the primary framework grains, in a number of samples chert and polycrystalline quartz form a significant percentage of the sediment. Using the classification of Pettijohn *et al.* (1973), the majority of sands fall into the quartz arenite bracket with some falling into the sublitharenite bracket. Only a very few samples can be called litharenite or lithic greywacke. Feldspar is present as a small percentage in most sandstones. The lithic fragments are mostly of sedimentary origin althouh there are some recognizable volcanic fragments in one of the Colony samples. In percentage terms, glauconite is relatively insignificant but it is important for environmental interpretation. Glauconite is in evidence in a

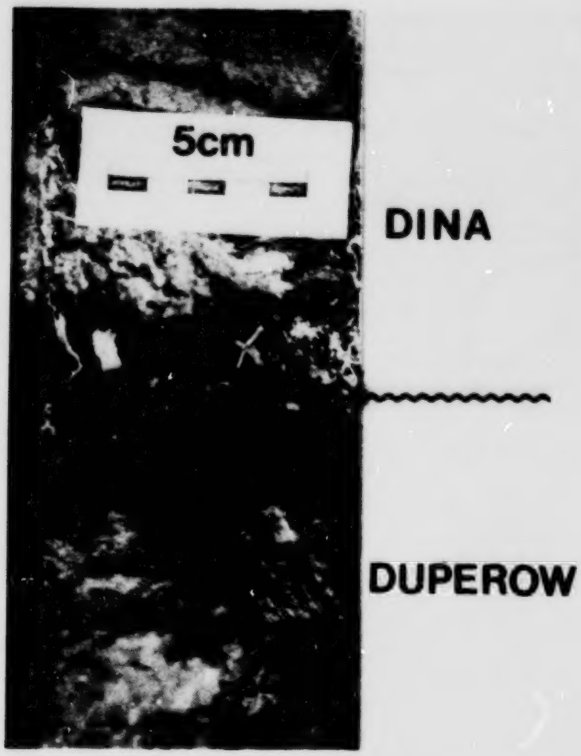


Fig. 3 - A13-19-52-23W3. Basal Mannville/Duperow contact.

portion of the samples from all Mannville units except the Dina. A single sample from the lower Cummings sand is also devoid of glauconite and generally resembles the Dina sand samples.

In general, sand grains are subangular to subrounded and moderately spherical. Sorting is moderate to good. As mentioned before, the grains range from silt to fine sand size. A negative, but nevertheless significant feature, is the lack of diagenetic change occuring within the sands. In some cases there are thin clay envelopes developed on the quartz grains, in others there is limited development of authigenic clays, particularly kaolinite and some illite (Fig. 4). Generally, authigenic mineral development is limited. Also evident is a lack of compactional features: even soft clay clasts and glauconite grains display only minor compaction or, commonly, none at all. Alteration of grains is limited to a few samples where feldspar and glauconite show some evidence of recrystallisation around the grain perimeter and along cleavage traces.

Porosity and permeability measurements are available for most cores. These show extremely high values for both porosity and permeability within the sand reservoirs. Calculated porosities are generally in excess of 30% and range up to 38% or higher, whilst permeabilities are often in excess of 1 darcy and have been recorded as high as 11 darcies in the Tangleflags area.

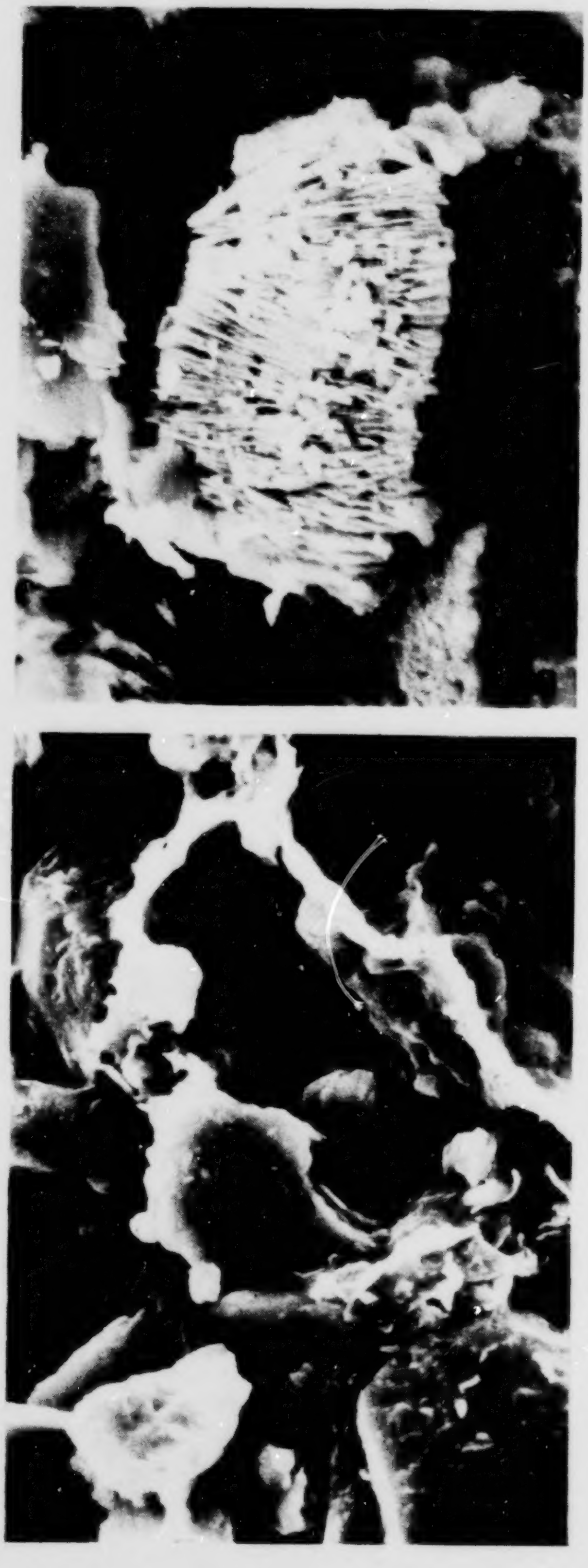


Fig. 4 - a) Authigenic kaolinite. b) Authigenic illite.

X-Ray diffraction (XRD) analysis of reservoir sands shows that they are quartz dominated and that clays form only a small percentage of the bulk volume. Kaolinite is generally the dominant mineral within the clay fraction.

Analyses of core samples, both commerically and specifically for this study, are naturally biased towards sands and even more particularly towards oil-bearing sands. The results are, therefore, applicable only to a portion of Mannville sediments but they do provide some relevant insights into their depositional and diagenetic history. The overriding petrographic characteristic of Mannville sands is the lack of diagenetic alteration. Porosity and permeability remain high because there has been little growth of autheigenic minerals and virtually no compaction. Within reservoirs oil emplacement has effectively "frozen" the sand in the same state as it was when the oil was emplaced. In water saturated sands there also appears to have been virtually no change in most instances.

DEPOSITIONAL ENVIRONMENTS

During Mannville time the early Albian sea transgressed from the northwest and, at its maximum extent, covered much of Saskatchewan (Williams and Stelck, 1975). The exact limits of the sea are unknown due to subsequent erosion and the problems of determining a shoreline from subsurface data. The shallow sea would be characterised numerous low islands, shoal areas, lagoons, coastal swamps, tidal inlets, and poorly defined coastlines. Because of the limited size and shallow nature of the sea there would have been a low tidal range and probably limited wave size; however, the area covered by small changes in water level would have been large because of low relief and very gentle slopes. Salinity is inferred to have been lower than normal sea water. This is a general picture of the Mannville sea; a number of lines of evidence leading to these speculations will be discussed below.

The low salinity is indicated by several lines of evidence; none of them is conclusive but they are certainly suggestive of brackish water. Trace fossils are abundant but megafaunal remains are almost totally absent. The exception to this is a few cores from the Marsden Field (township 44, range 26W3) where vast numbers of gastropods can be found in distinct layers in the sediments. These gastropod shells have evidently been washed in periodically, probably by storm surges, with normal, *i.e.* fossil free, sedimentation between. The gastropods are thin-walled forms with limited species diversity but high numbers; the species suggest brackish water conditions. (J. A. Lorsong, unpubl. data). The lack of calcareous walled megafauna or molds elsewhere indicates two possibilities: either lack of fossils or early dissolution of the shells. Abundant trace fossils show that organisms lived in these seas so the latter explanation, early dissolution, seems more likely (*cf.* Lorsong, 1981). A study of the foraminifera from well A13-19-52-23W3 shows agglutinated forms dominating which are good indicators of brackish water (Atkin, pers. comm., 1984). The general setting of the sea surrounded by a large landmass and infilling low areas that formed part of a large continental drainage system (Christopher, 1980) itself is strongly suggestive of a moderate to large influx of fresh water into a shallow restricted sea. That there was marine influence is unequivocal from the presence of some body fossils, trace fossils, and the presence of glauconite in the sediments.

The minerals themselves provide little information about their depositional environment. Glauconite suggests marine conditions. Mannville sands tend to be relatively mature with few unstable minerals, and well winnowed. This suggests long distance transport and/or prolonged working of the sediments. There are few indicators pointing to the source of the sediment. The presence of some volcanic and sedimentary rock fragments suggests a western or southern source rather than the Precambrian Shield to the north and east.

Sedimentary structures provide further evidence for the depositional environment envisioned above. Sands are massive or they display low angle cross-lamination with sets of laminae showing alternation of direction (Fig. 5). The massive aspect, particularly in the reservoirs, may be a result of the lamination being invisible in a homogeneous sand unit. Indeed, x-rays of core may show lamination in an otherwise structureless sand body. An alternative is that intense bioturbation may have destroyed all primary structure. The low angle planar lamination, sometimes with fanning of the laminae, is typical of a high shoreface or shallow bar (Harms *et al.*, 1982). Associated with the low angle lamination may be high angle planar, horizontal planar, and various scales of ripple cross-lamination, producing trough cross-bedding, typical planar cross-beds with the ripple foresets (Fig. 5) in evidence, or, occasionally, climbing ripples indicating a high suspended sediment load. In a few cases, grading may be visible within the laminae. These are consistent with a shoreface situation.

Whilst individual bedding contacts may be sharp, the general trend within Mannville sediments is coarsening up from shale to sand and fining up from sand to shale. These trends are visible on petrophysical logs and in core. In the finer grained sediments the shales may be massive or contain numerous "pin-stripes" of silt (Fig. 5). Massive shales may be formed in many environments. The pin-stripe bedding comprises silt beds which commonly exhibit gradational contacts with the overlying shales; this lithology is frequently found in intertidal flats (Reineck and Singh, 1980).

Intermediate between the shales and sands are a range of interlaminated sands/silts and shales. These vary from lenticular bedding through wavy bedding to flaser bedding (Fig. 5). The silts may or may not display primary structures. In themselves, these intermediate sediments give little environmental information beyond energy levels, but in association with other sedimentary structures or trace fossils the depositional setting may be determined more accurately.

In addition to the range of primary sedimentary structures found in the sediments, there are some syndepositional structures. These are soft sediment deformational features and microfaulting or slump structures. Siderite preserves deformational features or bioturbation extremely well, suggesting early cementation. Also, siderite is extensively developed as displacive nodular growth and replacement/cement growth in fine grained sediments. Pyrite, although less abundant than siderite, is common as nodualr growth, cement or infilling organic features such as root casts and some burrows.

An important environmental indicator found in the Mannville is coal and carbonaceous shale. Within the Tangleflags area, coal is almost always in evidence at the top of the Sparky. Coal is also found locally at the top of the Lloydminster, near the top of the Rex, near the top of the Waseca, at the top of the McLaren, and in the Colony. Associated with the coal, which may be only thin lenses and stringers of true coal, are shaly coal and carbonaceous shale. These all point to swampy conditions particularly as they normally overlie seat earths.

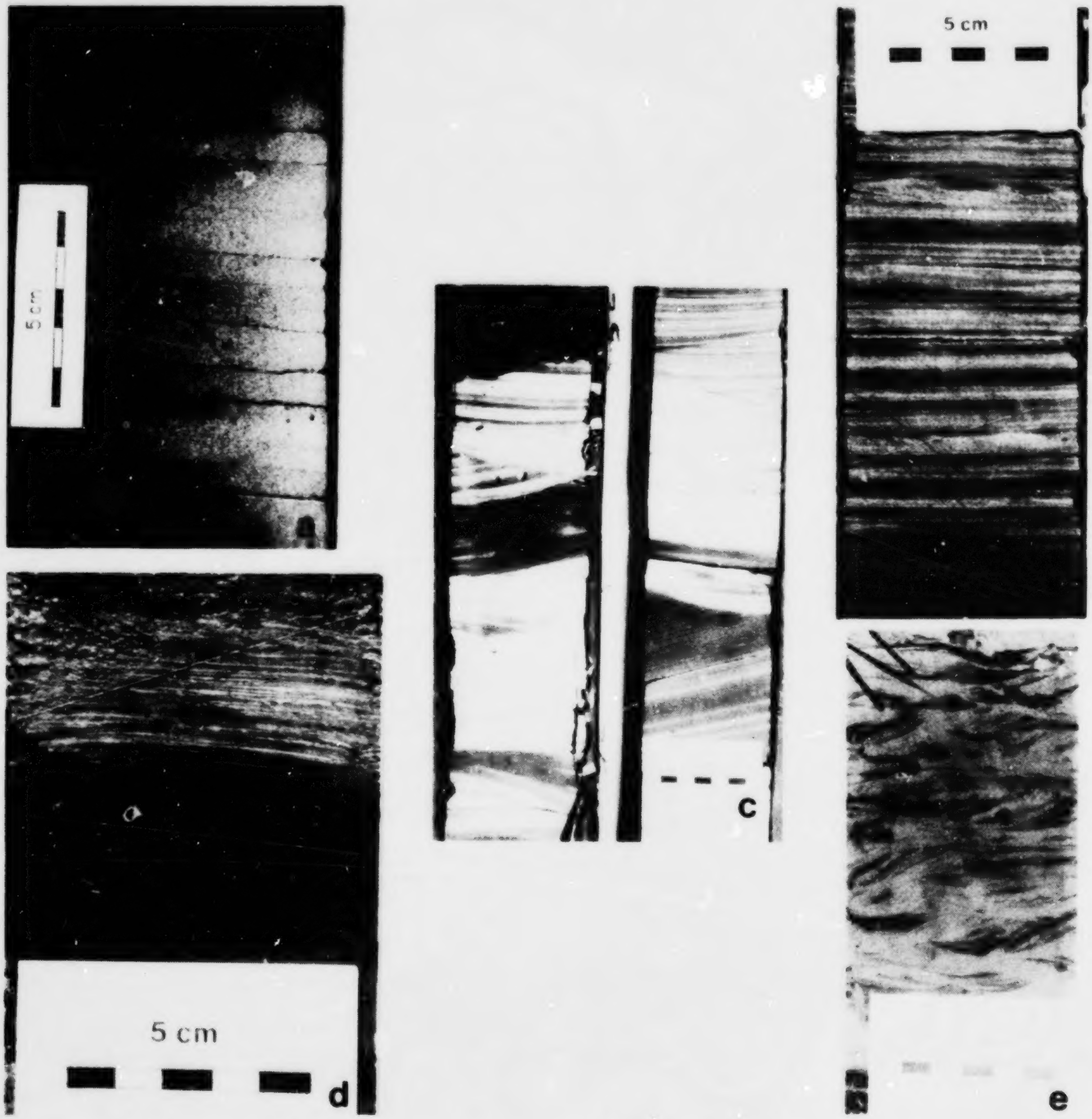


Fig. 5 - a) A10-34-50-25W3 (493.8 m below KB.). Low angle cross-lamination. b) A10-22-50-25W3 (519.5 m below KB.). Horizontal lamination. c) A6-14-50-25W3 (478.25 to 479.75 m below KB.). Trough cross-lamination. d) A14-24-50-25W3 (511.5 m below KB.). Pinstripe lamination. e) A10-22-50-25W3 (521.0 m below KB.). Flasers.

In the Tangleflags North Field some features unique in the Tangleflags area can be found. The Lloydminster and Cummings appear as a single thick sand on the logs and in core. This sand shows, in some cases, a subdued response on the spontaneous potential curve. This response is due to a high shale content in the sand. The shale appears as rip-up clasts and slump blocks (Fig. 6). In one core the clasts are imbricated; the clasts may represent thin shale laminae that formed cohesive units in an otherwise fluidised sand. Any movement that occured in the sand would break up the shale laminae, leaving imbricate shale clasts. The amount of shale in the sands varies from absent to abundant among cores; it is most abundant towards the base of the sand. Figure 7 is a subjective depicition of the areal extent of the thick sand in Tangleflags North showing its relationship to surrounding shales. Outside this area the Mannville sequence is "normal", with distinguishable Lloydminster and Cummings sands. This isolated feature is prominent on an east-west section (Fig. 8) in wells 10 to 13, inclusive. A lack of drilling to the northeast of Tangleflags North prevents accurate delineation of the sand in that direction. The general setting of sands with slump blocks and rip-up clasts of shale, surrounded by thick shale sequences, if placed in context with the rest of the Tangleflags area, indicates a tidal inlet open to the northeast.

STRUCTURE

The structure contour maps (Figs. 9, 10 & 11) show the Paleozoic erosion surface, the structure on the top of the Lloydminster, and the structure on the top of the Mannville. The Paleozoic surface lacks detail, giving a general indication of the features. The area of the oil fields is the most detailed portion of the contour maps; consequently the prime area for analysis is the Tangleflags Field and the area to the east. For this region the maps show a structural relief of 50 m or so in the lower Mannville and approximately 35 m at the top of the Mannville. The combined structural and palaeotopographic relief in the Paleozoic surface is approximately 100 m. Erosional highs and structural highs are approximately coincident. Elimination of the 50 m of post-Paleozoic structural relief leaves a maximum paleotopographic relief in the order of 50 m on the Paleozoic surface. This was effectively eliminated by the end of Cummings deposition and probably by the end of Dina deposition. The limited amount of data available for the Dina, indicates dramatic variations in thickness which are not seen in younger Mannville units. These thickness variations suggest an infilling of the paleotopographic lows.

A second pair of contour maps show the combined thicknessess of the Colony, McLaren, and Waseca (Fig. 12) and the Sparky, G.P., and Rex (Fig. 13). These maps show the relatively uniform thickness of Mannville units accross the Tangleflags area. The datum for these two maps is the Sparky coal. Presuming the coal to be horizontal or nearly horizontal at the time of deposition, the maps also show the depositional surface at the top of the Lloydminster and Mannville. In this form the maps display low depositional relief and, more importantly, a thinning of sediments on the structural highs. A combination of the structural and isopach maps therefore indicates that structure was active during, as well as after, Mannville deposition, resulting in a draping of sediments over the structural highs. The influence of structure on the depositional pattern also becomes more obvious in the upper Mannville.

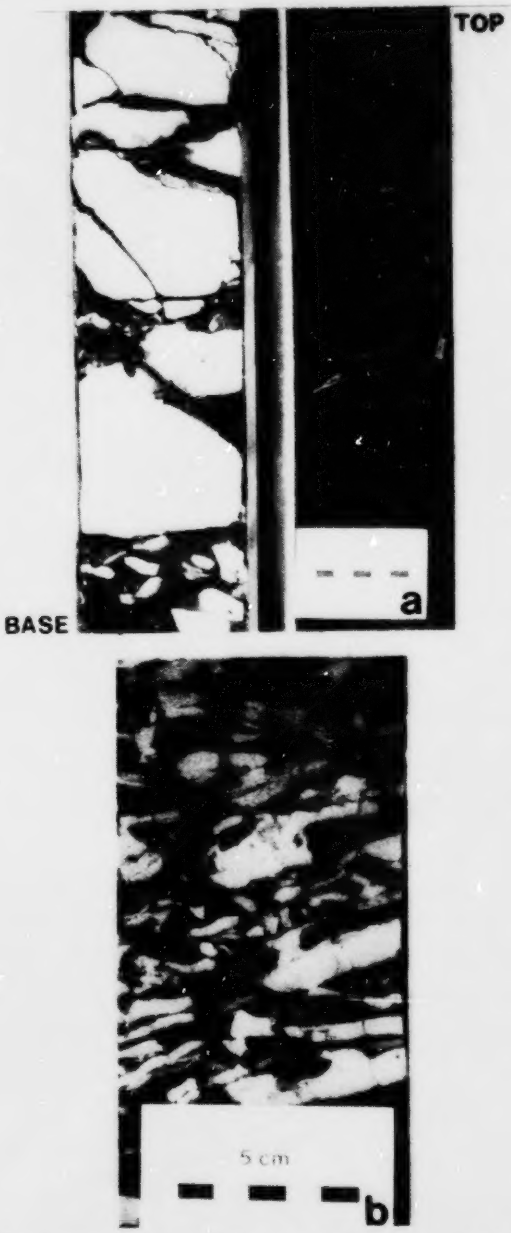


Fig. 6 - a) A1-14-50-25W3 (499.5 to 510.0 m below KB.). Slumped shale blocks on left supported in heavily oil stained sand. Massive, heavily oil stained sand on right overlying core on left. b) A14-15-52-25W3 (535-6 m below KB). Imbricate shale clasts in a heavily oil stained sand matrix.

DEPOSITIONAL AND STRUCTURAL HISTORY

In the Lloydminster area it is difficult to divorce structure from depositional history and both are certainly relevant to hydrocarbon accumulation in the sediments. Structural relief in the study area is in the order of 30 to 50 m; it is this structure that has been defined on seismic surveys and drilled for hydrocarbons. The depositional setting is such that there are

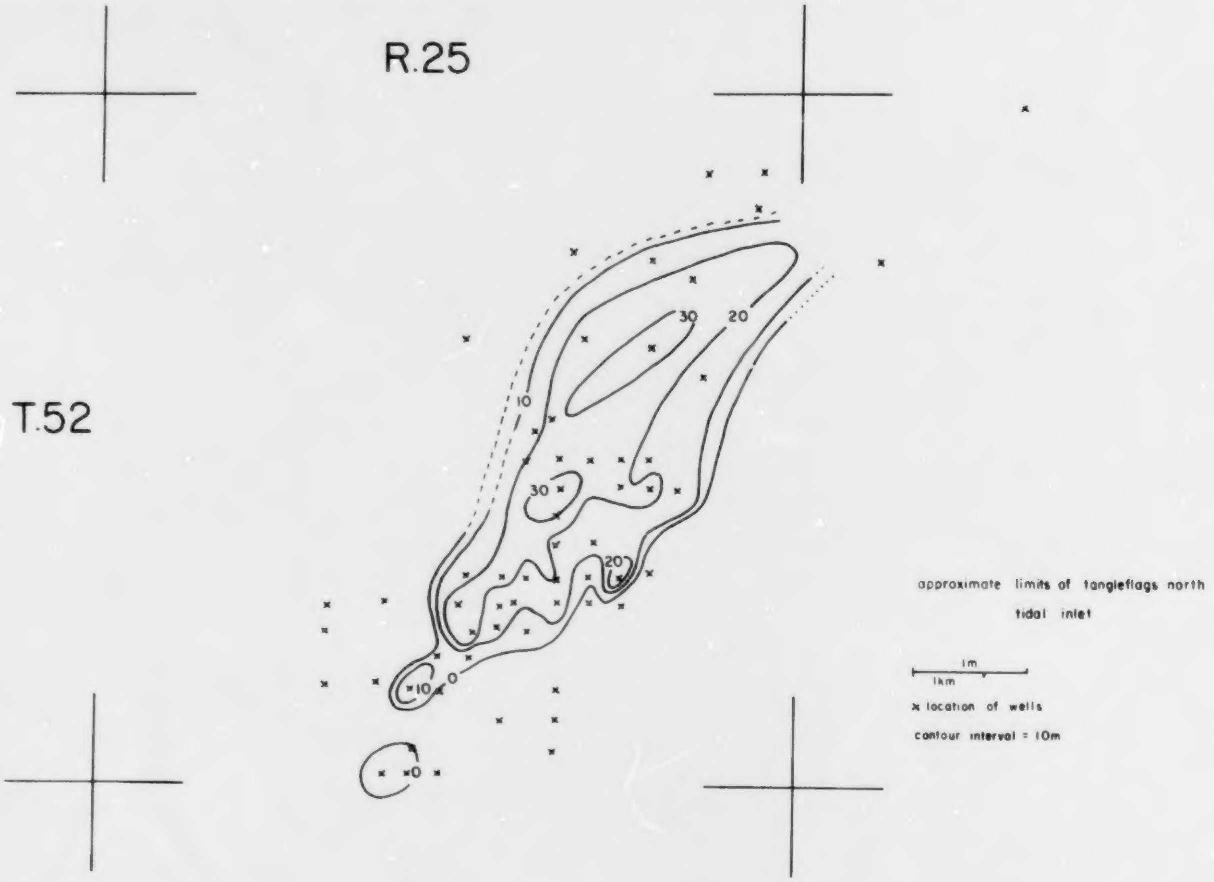


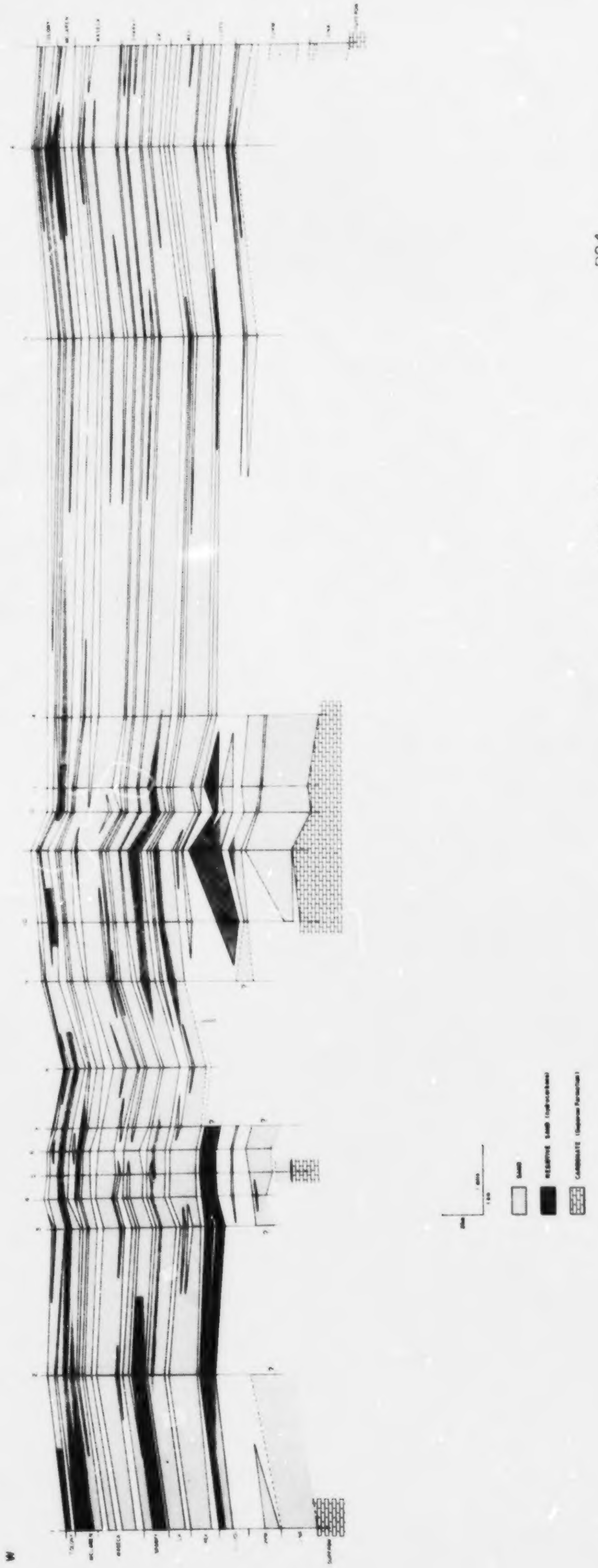
Fig. 7 - Subjective interpretation of the limits of the Tangleflags North tidal inlet deposit.

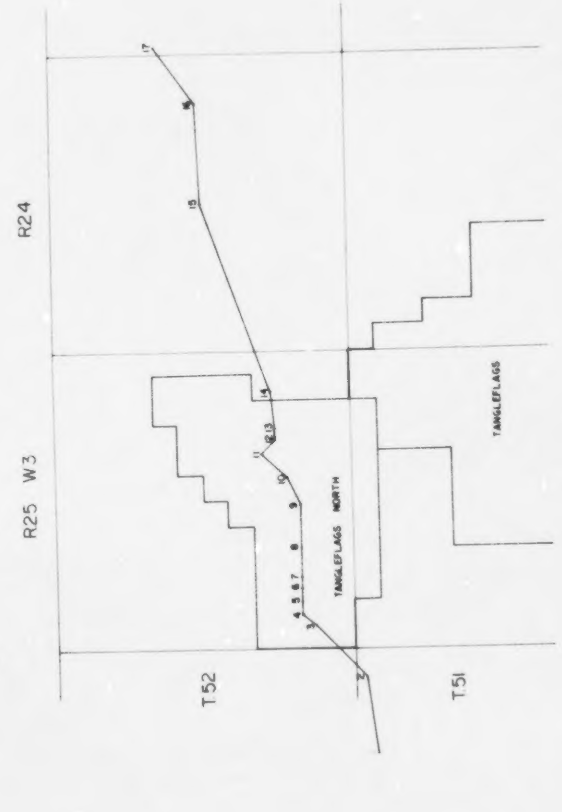
rapid, and often dramatic, lateral and vertical facies changes. These have been clearly displayed in a detailed study of Celtic Field cores by Lorsong (1980). The sediments are difficult to correlate laterally and the facies changes provide stratigraphic traps superimposed on structural features.

The structural influence explains the thinning or draping of sediments during Mannville time in the area of present structural highs. The depositional setting is a result of structural change, sea level change, and sediment influx. During Dina deposition, the Tangleflags area lay in a paleotopographic low with drainage northeast into a main northwest flowing channel (Christopher, 1980; Fig. 6). As base level changed in this valley system so sediments were deposited, filling in the low areas and draping over, or wedging out against, the highs. These processess continued into Cummings time. By the middle of Cummings time isostatic sea level rise was sufficient to flood the Tangleflags area. The upper Cummings represents the first transgressive event of the Mannville. Following the transgressive event, the Lloydminster unit is a record of the associated regressive event. Locally, coals are in evidence at the top of the Lloydminster, indicating subaerial exposure of part of the area at least (erosion may well be responsible for the localized nature of the coal deposit). Above the Lloydminster, the Rex probably represents one complete cycle, a cemented zone typical of the lower Rex contains trace fossils indicative of a shoreface situation (Wilson, 1982) and a local coal near the top suggests subaerial exposure. The Sparky and G.P. may represent one or two cycles of sea level rise and fall but the Sparky coal shows a widespread regression and subaerial exposure at this time. Above the Sparky are at least two more cycles with regressive phases in the Waseca and McLaren. The Colony is basically non-marine and represents the final retreat of the Mannville sea. Overlying the Colony are the marine shales and sands of the Lower Colorado Group.

In Tangleflags North the Lloydminster and Cummings in many wells are inseparable; they appear either as thick sand sequences or thick shale sequences. The local setting and sedimentary features indicate sedimentation in a shallow tidal inlet. It seems likely that sedimentation and subsidence during the upper Cummings-Lloydminster transgressive-regressive event kept pace with sea level change, resulting in continous tidal sedimentation. This is preferable to invoking deep erosion during Lloydminster time followed by rapid sedimentation when there is no obvious mechanism for such an event in so limited an area.

In essence, therefore, Mannville deposition in the Tangleflags area is dominated by variations in relative sea level in an area of low relief. The sedimentary sequences are effec-


W
E
SAND
RESERVOIR SAND (hydrocarbons)
CARBONATE


R24
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TANGLEFLAGS NORTH
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Fig. 8 - Cross-section through Tangleflags North.

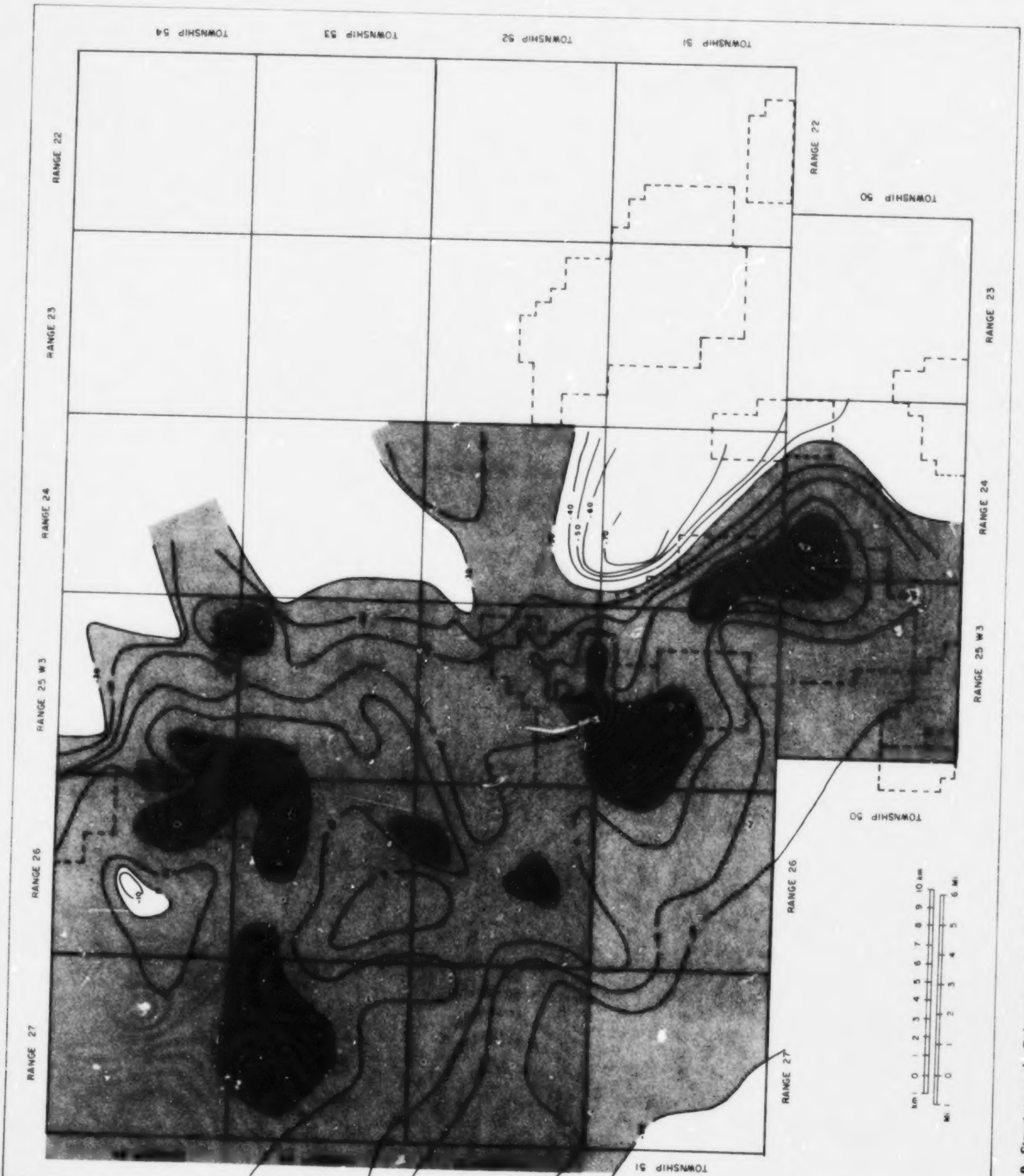
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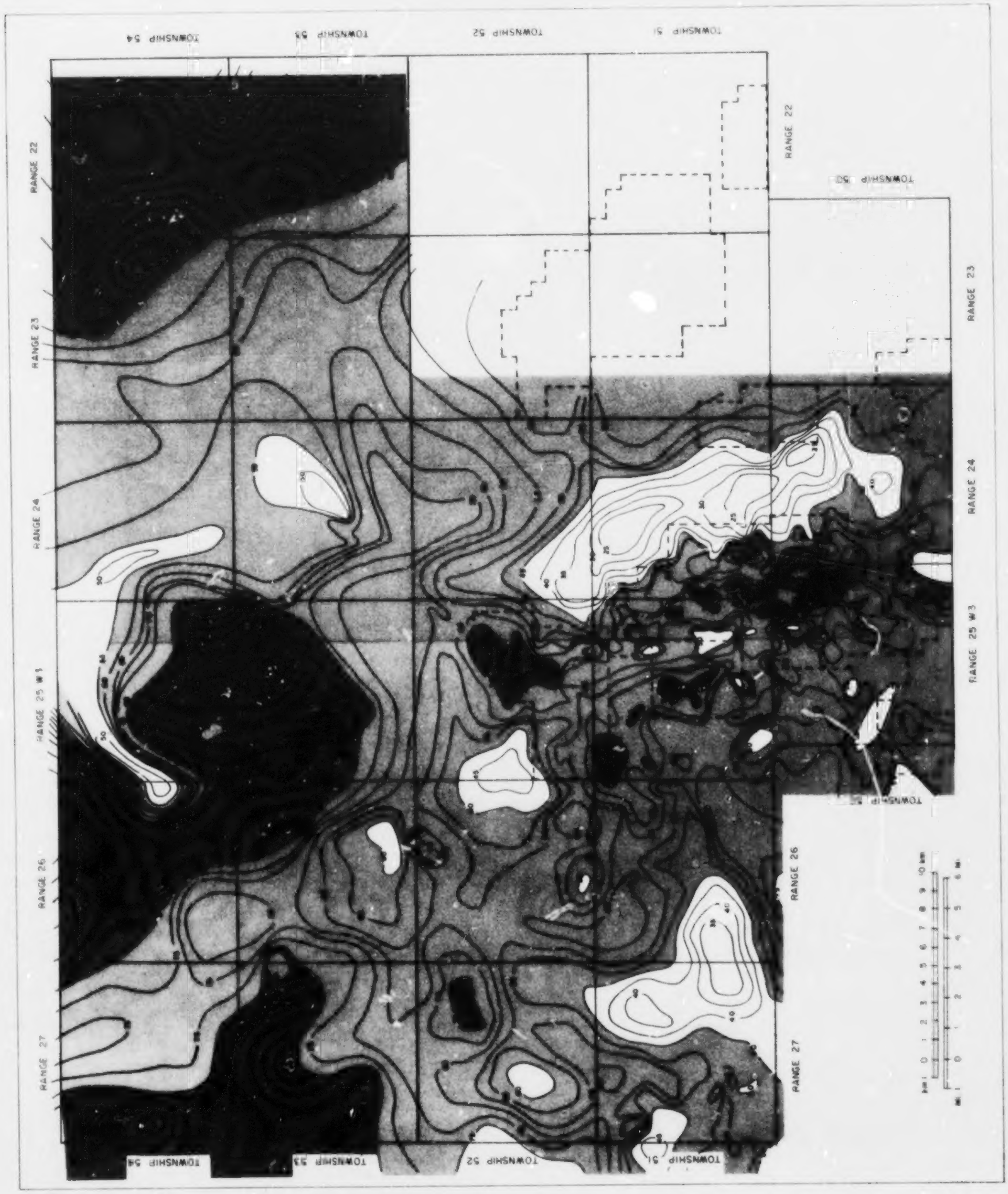
Fig. 9 - Structure on the Paleozoic erosion surface. Dark shading represents high areas, no shading represents low areas. Contour interval is 10m; datum is sea level.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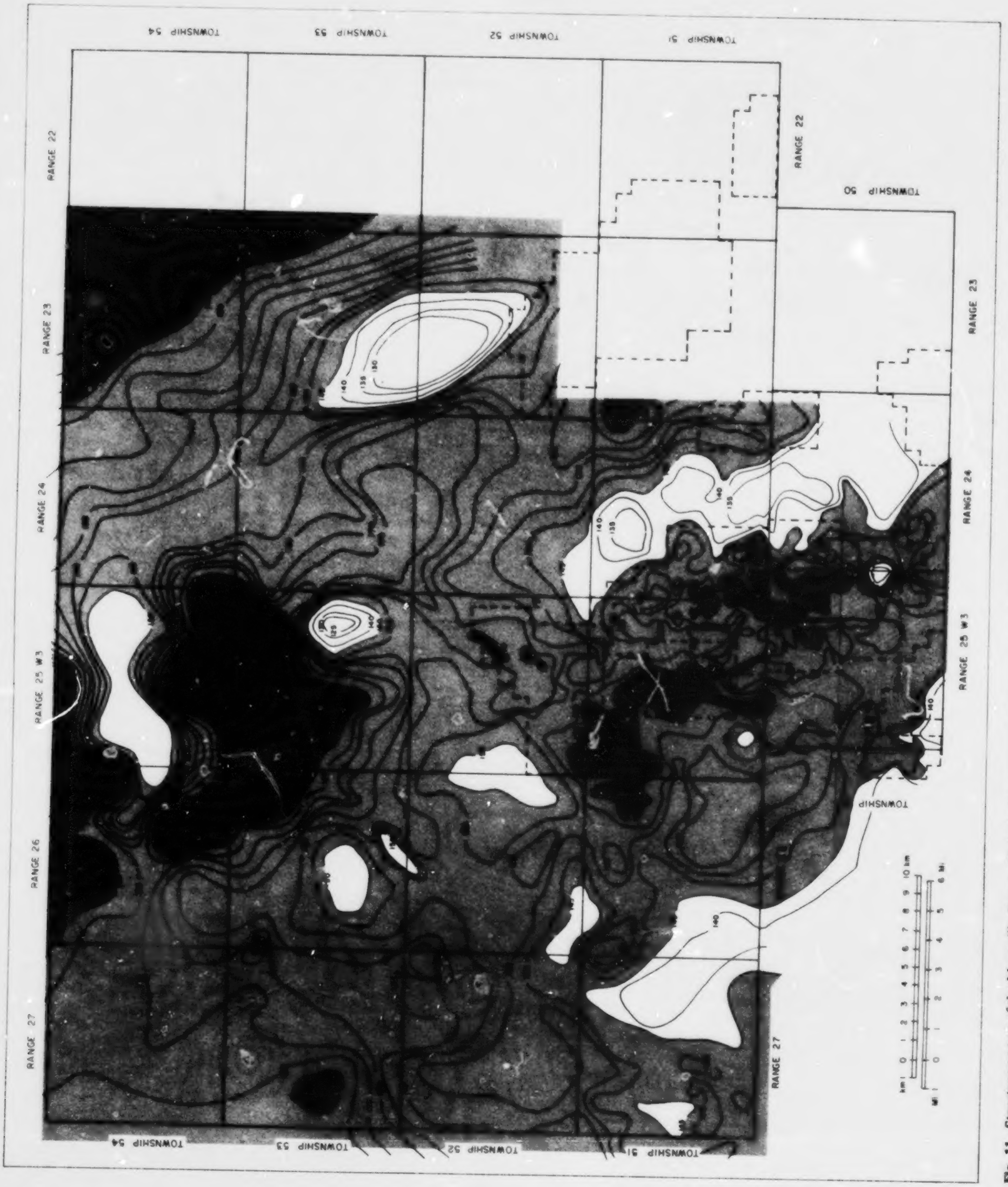
RANGE 27
km 0 1 2 3 4 5 6 7 8 9 10 km
mi 0 1 2 3 4 5 6 mi

Fig. 10 - Structure on top of the Lloydminster unit. Dark shading represents high areas, no shading represents low areas. Contour interval is 5 m; datum is sea level.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140
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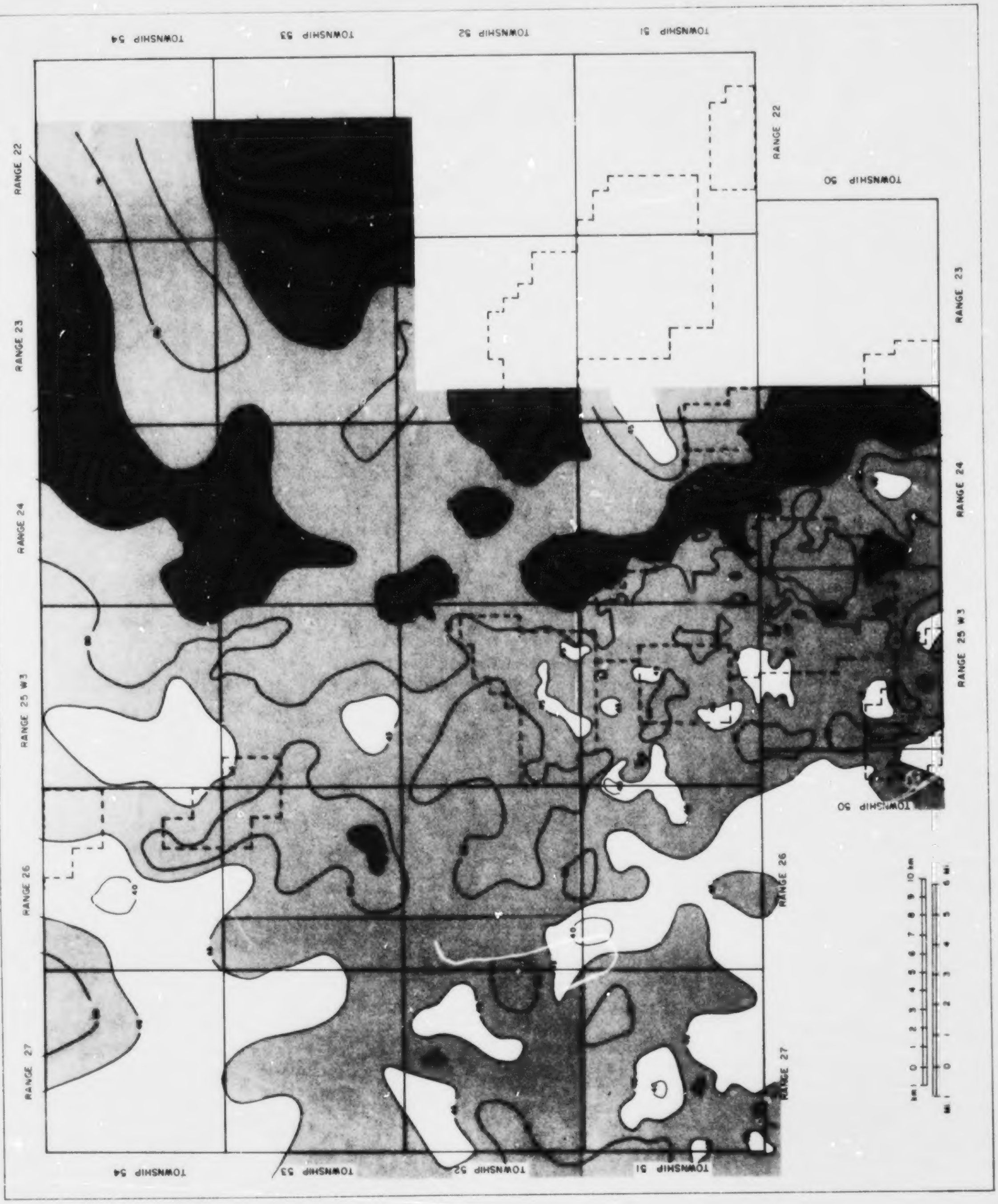
130
125
km 0 1 2 3 4 5 6 7 8 9 10 km
Mi 0 1 2 3 4 5 6 Mi

Fig. 11 - Structure on top of the Mannville Group. Dark shading represents high areas, no shading represents low areas. Contour interval is 5 m; datum is sea level.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RANGE 27
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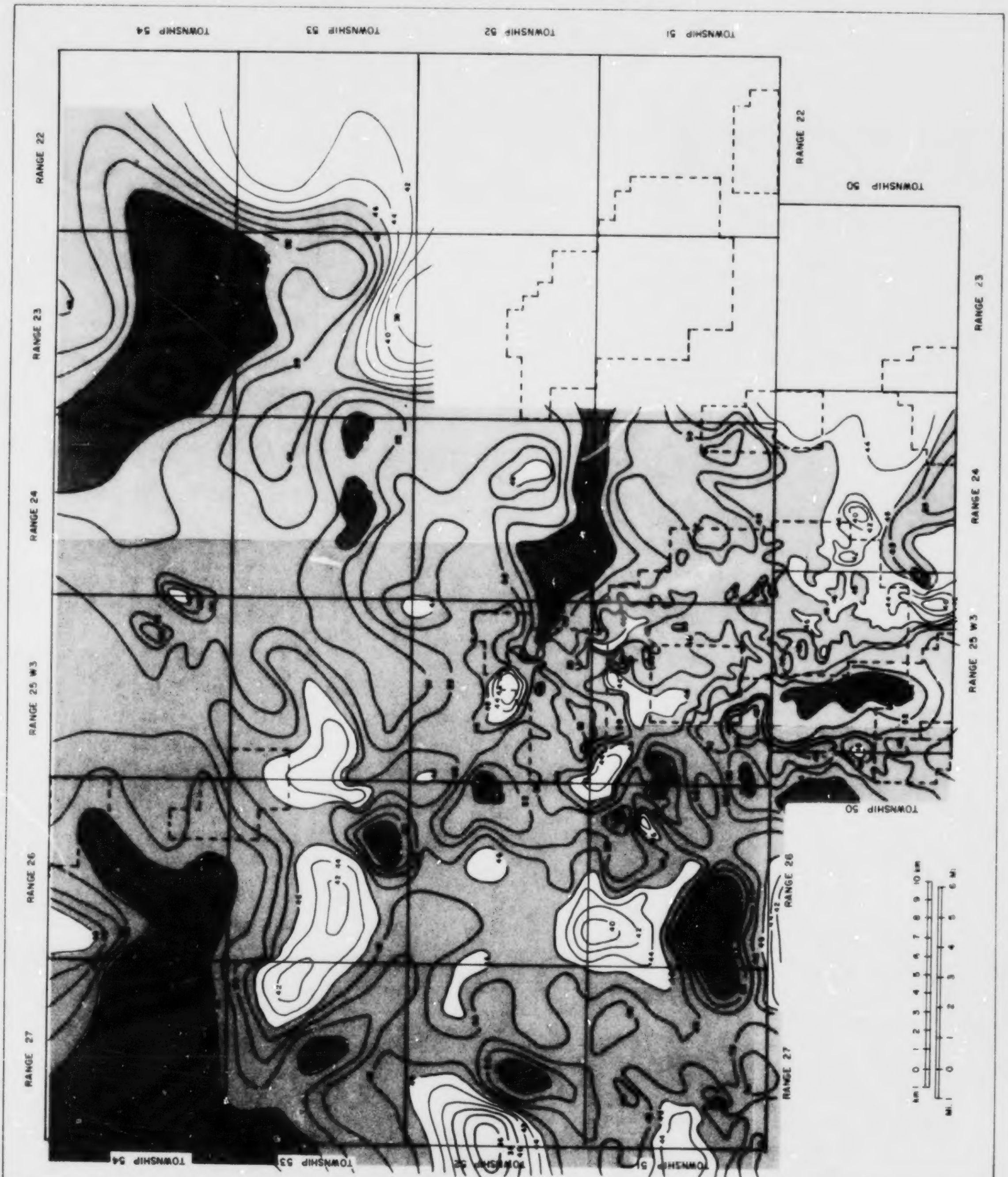
km 0 1 2 3 4 5 6 7 8 9 10 km
mi 0 1 2 3 4 5 6 mi

Fig. 12 - Isopach map of combined Waseca, McLaren, and Colony units. Dark shading represents thick sediments, no shading represents thin sediments. Contour interval is 5 m.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42
44
km 0 1 2 3 4 5 6 7 8 9 10 km
Mi 0 1 2 3 4 5 6 Mi

Fig. 13 - Isopach map of combined General Petroleums, Sparky, and Rex units. Dark shading represents thick sediments, no shading represents thin sediments. Contour interval is 2 m.

tively identical in the low and high areas but sediments are draped over the highs. These highs are also characterised by periods of more prolonged subaerial exposure. The sands and shales of the Mannville represent diachronous events with marine sedimentation starting in the low areas, transgressing to cover the highs, followed by a reversal. For non-marine sediments the trends are, of course, opposite. With the low relief of the area, sea level changes need only be small to effect a dramatic increase in areal extent.

HYDROCARBON ACCUMULATIONS

The high porosity and permeability of Mannville sands present no barriers to the migration of oil and gas. Unfortunately the lateral continuity of the sands remains the major problem (Lorsong, 1980) and the correlations in Figure 8 are somewhat tenuous. Whilst individual sands and shales may not be continous, packages of these sands (the sands of Figure 8), probably do have lateral hydrodynamic continuity. The depositional setting of the sediments suggests lateral continuity, at least over an area of several townships. Hydrocarbons, as heavy oil and natural gas, appear in all the units of the Mannville with the exception of the Dina, oil occurs in the Cummings in only one well within the study area. The single exception is oil in the undifferentiated Lloydminster/Cummings sands of Tangleflags North (Fig. 8). Elsewhere, even in places where the Cummings is higher than oil bearing Lloydminster sand it contains no oil.

The Lloydminster sand, the regressive sand of the first major Mannville marine pulse, appears to contain oil, or oil stain, throughout most of the study area. It appears to be the major conduit for migration of oil in the Tangleflags area. Lateral migration of oil from the Lloydminster sand into Cummings sand on the same level or higher has been prevented by the well developed Lloydminster shale, assuming that oil emplacement occurred after structural activity had ceased. Figure 8 is misleading insofar as only the more important resistive sands are picked. Oil stained sands and thin oil sands extend beyond the major reservoirs indicated in the figure. In addition, the structurally and stratigraphically higher reservoirs are more gas prone, particularly in the northern portion of the area.

The principal trapping mechanism for hydrocarbons within the Tangleflags area is the 30 to 50 m of structural relief. Because the present structural highs are also the sites of depositional highs during Mannville time, the oil is trapped where the sediments are draped over the highs. As mentioned above, the nature of Mannville sedimentation is such that there are rapid lateral facies changes (Lorsong, 1980). These facies changes also provide a trapping mechanism and thus modify the dominant structural trapping. The effects of stratigraphic trapping can, therefore explain isolated pockets of hydrocarbons in structural lows or the occasional absence of hydrocarbons in high areas. Figure 8 illustrates these trapping mechanisms. In wells 10 through 13 the oil in the Lloydminster "channel" is in a stratigraphic trap; this sand is enclosed by thick shale sequences (wells 9 and 14). The bulk of the hydrocarbons are to be found in the structural highs with some lateral control by porosity and permeaility variations within the sands.

CONCLUSIONS

Mannville sediments within the Tangleflags area were deposited along the margins of an extremely shallow inland sea of reduced salinity. Prior to the initial marine incursion, pre-Mannville topography was largely in-filled by non-marine sands and shales of the Dina and lower Cummings. Elimination of pre-Mannville topography left a surface of low relief over which the sea encroached. Small changes in sea level resulted in large variations in the amount of land covered by water. The initial marine transgression is represented by the upper Cummings with the regressive phase represented by the Lloydminster. The Rex comprises another marine pulse, the G. P. and Sparky one or two pulses, and the Waseca and McLaren at least two pulses. At the top of the Sparky is a coal that is ubiquitous in the Lloydminster area; it represents a widespread regression with low-lying coastal swamps dominating the landscape. Virtually every coal and coaly shale in the area is underlain by seat earth. At the top of the Mannville, the Colony is dominated by non-marine sediments representing the final retreat of the early Albian sea from the Lloydminster area prior to the transgression of the Colorado sea.

Sedimentary structures, body fossils, trace fossils, and mineralogy all indicate a low-lying coastal plain which was, at times, completely inundated by the sea and, at other times, mostly above sea level as a coastal swamp. The sheet sands of the area therefore represent primarily transgressive and regressive beach and bar sands. Shales and interlaminated silts and shales were deposited in a variety of environments peripheral to the sands; upper offshore, lagoon, tidal flats, and supratidal areas. Coals, some of the carbonaceous shales, and seat earths represent times of subaerial exposure. The major exception to this general picture is in Tangleflags North where the Cummings and Lloydminster sand were deposited in a tidal inlet surrounded by shales of a tidal flat area. These is no evidence of any fluvial sediments in this area and the proposed depositional setting precludes the possibility of any.

The mechansim responsible for isostatic sea level fluctuations is almost certainly a combination of factors. The Lloydminster area falls on the margin of the subsiding Western Canada Basin; pulses of subsidence followed by periods of sediment infilling are probably the main cause of sea level changes. In addition, the study area lies in a region of active salt solution, such that related subsidence may also have played a role in shaping the depositional and structural patterns of the Tangleflags region. The Tectonic events occurred during Mannville deposition and played a role in the distribution of depositional environments. There is a subtle thinning of the sediment pile over structural highs, particularly in the Tanglefalgs Field and adjacent areas where the detail is sufficient to delineate such trends. Structural draping has definetely played a role in hydrocarbon trapping, forming the main oil pools, although rapid lateral facies changes have created stratigraphic traps that are superimposed on structural traps.

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DEPOSITIONAL ENVIRONMENT OF THE CUMMINGS COAL AND ASSOCIATED SEDIMENTS, WINTER-SENLAC AREA, WESTERN SASKATCHEWAN

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ABSTRACT

Although coal is a minor constituent of the Mannville Group, the microscopical components reflect the peat forming environment and many aspects of the regional depositional setting which, inturn, help to determine the depositional environment of the associated heavy oil sands. Sedimentological analysis of 19 cores, sediment distribution trends determined from 235 geophysical well logs, and petrographic analyses of 24 coal samples, were conducted to study the depositional environment of the Cummings coal and underlying Cummings and Dina Formations in the Winter-Senlac heavy oil area.

The erosional relief on the unconformity surface, and the northwest-southeast trending Battleford arch appear to control the distribution of the Lower Mannville sediments. The Dina Formation comprises ripple bedded and structureless sands, lying unconformably on the pre-Cretaceous erosional surface. The basal sand represents linear channel-fill deposits in the Senlac and North Senlac areas and forms part of a thick paleovalley-fill deposit in the northwest. The Cummings Formation is a coastal marine sequence characterized by coarsening upward beach and lower sand flat sediments in the west that pinch-out eastward into bioturbated interbedded sand and shales of a mixed sand and mud flat. The transition from fluvial to marine sedimentation is represented within a thick basal sand deposited in fluvial channels subsequently transgressed by tidal channels. In the Winter Field, channel bank collapse conglomerates and abundant marine palynomorphs provide evidence of a tidal channel. Fine grained, ripple laminated and low to medium angle, planar cross-laminated sands are well elutriated in the upper part of the sequence inferring considerable wave influence.

The Cummings coal is an interbedded, thinly banded, humic coal with carbonaceous shale partings. The thickness of the coal/carbonaceous shale interval ranges from 0.5 m in the north to 5.5 m south of Senlac. The coal: clastic ratio and frequency of shale interbeds are greatest in the south indicating that the peat forming environment was less stable. The coal in the Winter area is detrital in nature and characterized by abundant densinite derived from a coastal marsh flora environment. Coal in the south formed from *in situ* peat; gelified, structured huminite typifies peats deposited in acidic, fresh water swamps. Marine palynomorphs increase from south to north reflecting the marine influence. Total sulphur in the coal is high (4.38% to 10.82%); mostly this is organic sulphur. The Dina and Cummings sediments and Cummings coal therefore represent a transition from fluvial to nearshore marine to coastal swamp/marsh environments.

INTRODUCTION

The Lower Cretaceous Mannville Group in the Lloydminster area is a sandstone-shale sequence including numerous coal beds Reserves in the order of 500 million m^3 of heavy oil (Vigrass, 1977) are contained within sandstone beds throughout the interval. The depositional environments of these sandstone reservoirs are somewhat complex. A sedimentological study of the Dina and Cummings Formations was undertaken together with a petrographic study of the Cummings coal, to aid in unravelling the complicated Mannville depositional history.

Coal beds occur at various stratigraphic intervals in the Mannville Group (Lorsong, 1979). As coal seams derive from ancient peat deposits, that accumulated in truly continental or marginal marine environments, certain inferences regarding the depositional environments of the coal bearing clastic interval can be made. An investigation of the depositional trends of the coal beds and coal bearing sequences is therefore considered vital to a study of the depositional environment of the Mannville sediments. Additionally, a detailed petrographic study of Mannville coals can provide much useful information on the geology of the coal/peat deposits.

The study area is located in west-central Saskatchewan within Townships 37-43 and Ranges 24-28W3 (Fig. 1). The clastic interval selected for study comprises the Lower Mannville, Dina and Cummings Formations of Vigrass (1977) (Fig. 2). The pre-Cretaceous unconformity marks the base of the interval and the Cummings coal marks the top. In the Senlac Field the coal underlies the Lloydminster heavy oil reservoir, while in the Winter Field, a 1 m thick shaly bed separates the Dina/Cummings reservoir from the overlying Cummings coal.

The lithologies of the Dina/Cummings clastic interval and the Cummings coal are identified from geophysical well logs from 235 wells and in 19 cores, located in three regions: Senlac, North Senlac and Winter. Thirty-eight coal samples were collected throughout the coal and carbonaceous shale interval for petrographic study. Heating values were obtained for coal samples from the Winter Field. Palynological analyses of 56 samples were conducted by Dr. E. M. V. Nambudiri (1983, 1984) of the Energy Research Unit, University of Regina. Percentage of sulphur (total sulphur and organic sulphur) was determined on coals in all three regions.

There has been no specific previous environmental work done on Lower Mannville sediments in the study area. Williams (1963) provides a regional synthesis of environmental north, where the erosional relief has been masked by a thicker Dina/Cummings sediment, to 5.5 m south of the Senlac area,

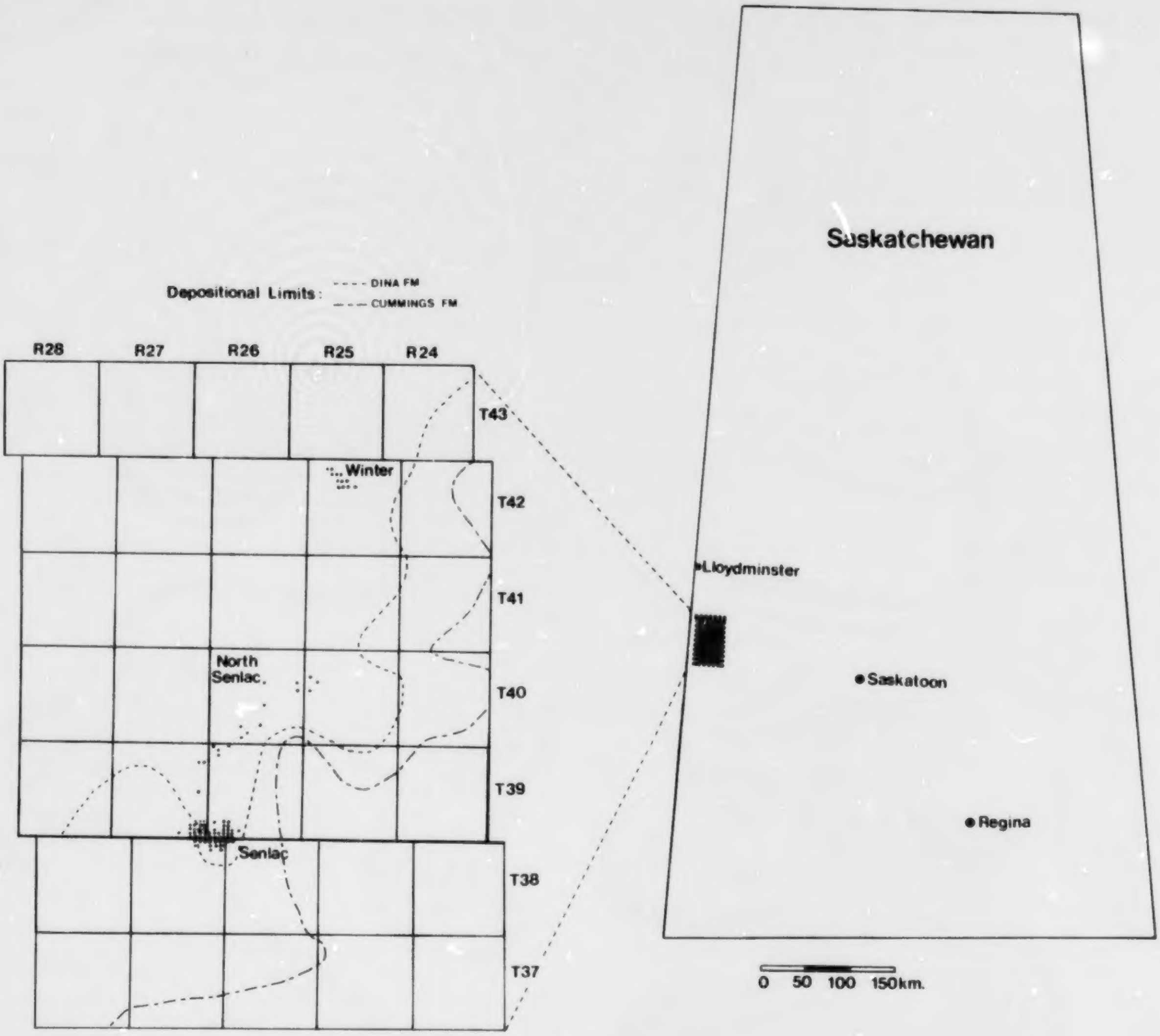


Fig. 1 - Location map of study area showing the depositional limits of the Dina and Cummings Formation.

interpretations for the McMurray and lower Clearwater Formations in Alberta that is generally considered equivalent to the Dina and Cummings Formations. Numerous studies by Orr, Johnson and Manko (1977); Putnam (1982) and Vigrass (1977) suggest that the Dina, in the Lloydminster area, is a fluvial deposit infilling paleotopographic lows and thereby reducing the relief on the pre-Cretaceous unconformity. Gross (1980), in a regional study of east-central Alberta, described the Dina interval as comprising "enormous sand-filled channels" which were deposited in large valleys on the Paleozoic surface. The overlying Cummings Formation is considered to be a marine clastic sequence deposited during a southward transgression of the Clearwater sea. According to Leung (1976), the Cummings coal formed during a brief period of emergence.

GEOLOGY OF THE DINA AND CUMMINGS FORMATIONS

THE PRE-CRETACEOUS UNCONFORMITY

Pre-Cretaceous strata in the Winter-Senlac area comprise the Upper Devonian Duperow, Birdbear and Torquay Formations (Kent, 1968); Birdbear and Torquay sediments subcrop only in Townships 37 and 38. A structure contour map on the unconformity (Fig. 3) reveals a regional south-southwesterly dip (approximately 2 m/km) and the character of the pre-Cretaceous paleotopographic relief. The Battleford arch, a northeastern extension of the Sweetgrass arch in Alberta, extends along the eastern border, through Range 24. A well defined ridge, rising 40-50 m above the erosion surface, trends west through Township 39. This extension of the Battleford arch is transected by a small paleovalley in the Senlac Field. The valley is a local feature which joins a regional paleovalley extending westwards from the centre of the study area.

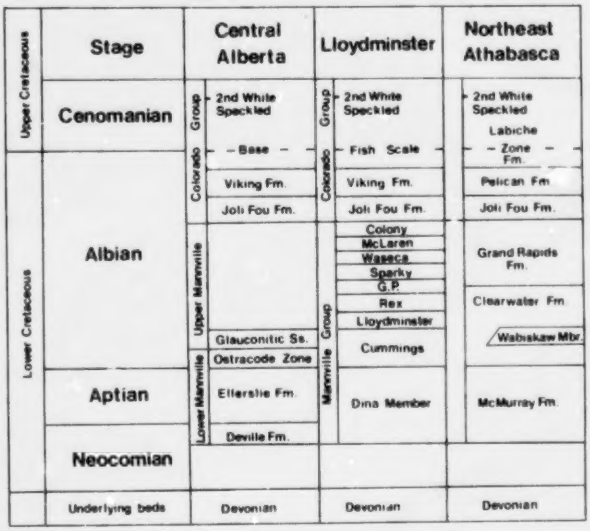


Fig. 2 - Stratigraphic correlation chart, after Tilley and Longstaffe 1984, modified.

REGIONAL SETTING OF DINA AND CUMMINGS FORMATIONS

In the northwest of the study area, the Cummings and Dina Formations reach a maximum thickness of about 55 m. Here, the interval is characterized by a thick basal sand (20-30 m) overlain by a shale and one or two sand units of appreciable thickness (up to 5 m). Towards the southeast, the formations thin and finally pinchout over the Battleford arch.

The Dina Formation comprises most of the basal sand unit lying unconformably on Upper Devonian rocks. Mapping of the sand unit reveals two major trends in development: 1) a linear body running through the Senlac Field, following the paleovalley axis and continuing northeastward along the nose of the ridge through North Senlac and, 2) a more extensive sheet of sand thickening northwestwards from the centre of the study area.

The Cummings Formation displays a much more variable character. A sinuous northeast-southwest belt of interbedded, thin sands and fine grained sediments parallels the Battleford arch and pinches out against the northern and western flanks of the ridge. In the west and northwest, the Cummings Formation changes its character from fine grained, interbedded sediments into a coarsening upward sequence, both being capped by a 2-3 m thick sand. The sand is silty southwest of the Winter area but becomes cleaner to the west. In the Winter Field, the boundary between the Dina and Cummings Formations is poorly defined, but it is more easily delineated in wells to the north of the field where the Cummings Formation is characterized by a fining-upward sand.

Sedimentology

Sedimentological analysis of the Cummings and Dina Formations is hindered by a number of factors: 1) the clustering of cored wells, 2) a minimum of 40 acre spacing between wells, 3) lack of a complete Dina/Cummings interval in some cored sections, 4) poor core quality, and 5) intense oil saturation masking sedimentary structures.

In the Senlac Field, the cored Dina/Cummings sediments is a general fining upward sequence that, according to well logs, increases in thickness down the paleovalley slope. Overlying the paleovalley, the sequence consists of intensely bioturbated (*Ophiomorpha* burrows?), fine-grained sand grading into a dark grey, silty shale displaying syneresis cracks and distrupted pinstripe bedding. A rooted, muddy shale (average 50 cm in thickness) caps the sequence.

The Dina Formation in the North Senlac area consists of fine to medium grained structureless and ripple and ripple-drift laminated sand displaying a slight tendency to fine upward. Where the sand thickens (e.g. 27 m in well 14-32-39-26W3) both Cummings and Dina sediments occur but the formation boundary is hard to define. The basal portions of the sand are predominantly ripple bedded (internally the laminae are defined by carbonaceous material) while the upper parts are dominated by multidirectional planar cross-lamination. An interbedded facies of rippled sand/silt and shale occurs throughout most of the cores from North Senlac. It varies from a non-bioturbated sediment, rich in carbonaceous detritus, at the base (Dina Formation) to intensely bioturbated, with discreet burrows in the upper part (Cummings Formation). Shales are bioturbated and contain similar amounts of carbonaceous material as the interbedded sediments. A matrix supported conglomerate (approximately 1 m thick) occurs at the base of the core in well 2-21-40-26W3; it consists of small (1 cm diameter), unoriented, lithic pebbles mixed with well preserved plant remains (twigs) and pyrite nodules.

In the Winter Field, the Dina/Cummings interval consists, almost entirely, of lithologically homogeneous, fine to very fine grained, quartzose sand. The degree of elutriation improves vertically and is manifested by the oil/water contact. Sedimentary structures consist of alternating ripple and ripple-drift lamination and low to medium angle planar cross-lamination. Some small scale trough cross-lamination occurs at the base of some cores and swash-zone lamination and hummocky cross stratification were tentatively identified at the top of the sand.

The homogeneity of the sand is disrupted by an intraformational conglomerate composed of finely laminated, deformed shale clasts (the largest being the entire width of the core barrel). A thin, intensely bioturbated interbedded sand and shale facies (similar to the upper sediments at North Senlac) overlies the sand in most wells. Well core 10-28-42-25W3 deviates from this general pattern by exhibiting a 10 m thick structureless shale, containing abundant pieces of coalified wood, between the sand and the Cummings coal.

THE CUMMINGS COAL

The Cummings coal interval is an interbedded sequence of coal and carbonaceous shale; the thickness and frequency of occurrence of the shale interbeds varies throughout the study area. For convenience, the complete coal/carbonaceous shale interval is referred to as the Cummings coal.

The Cummings coal is a laterally continuous bed that pinches out to the east as a result of non-deposition over the paleopositive relief of the Battleford arch and associated ridge. The thickness of the coal (Fig. 4) ranges from 0.5 m in the where a roughly circular "dome" of coal overlies sediments deposited in, or on, the margins of the Senlac paleovalley. Preliminary well log correlations to the west indicates that the coal in the Winter-Senlac area, is part of a much larger coal deposit that extends into east-central Alberta and covers an area of approximately 16,000km^2.

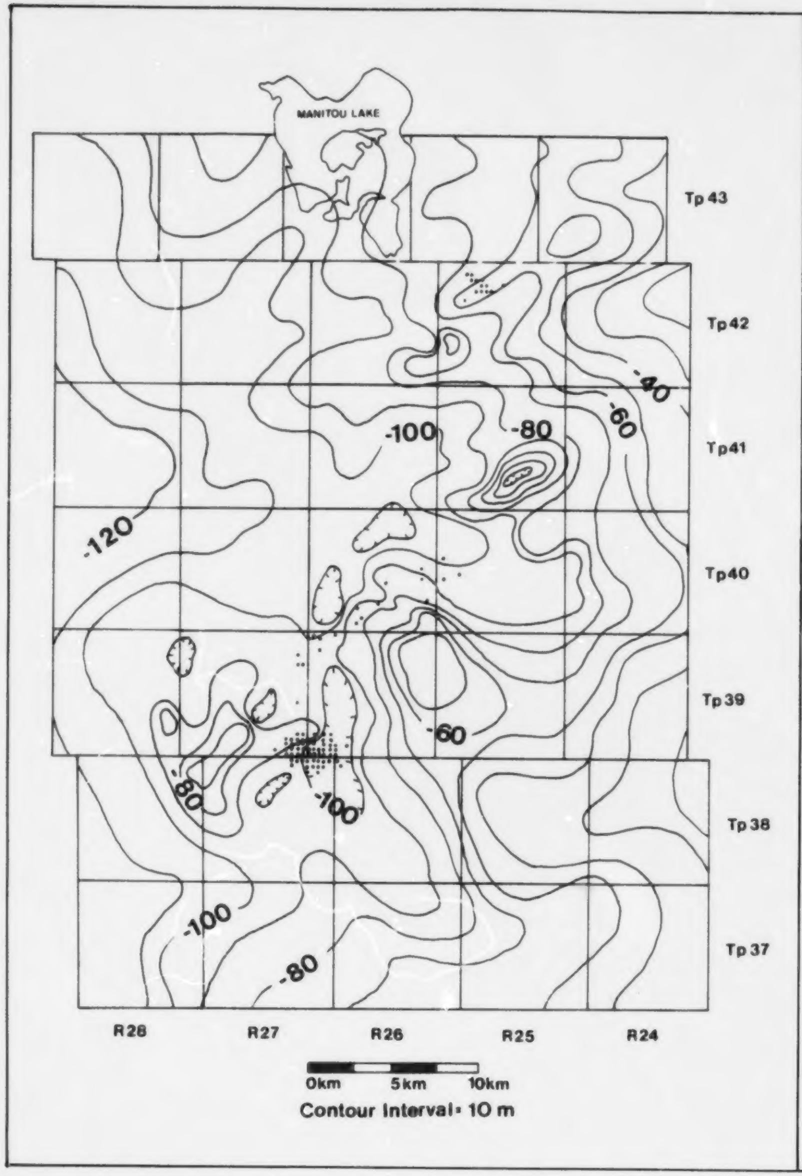
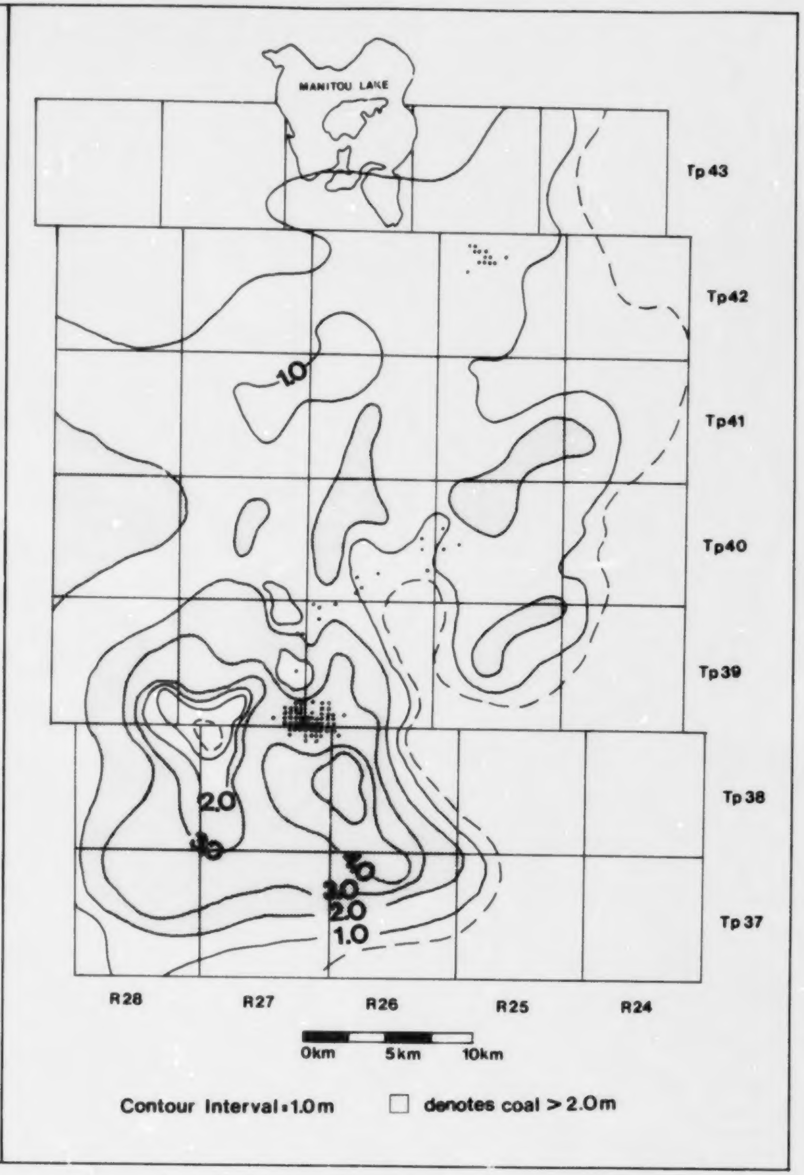

MANITOU LAKE
Tp 43
Tp 42
Tp 41
Tp 40
Tp 39
Tp 38
Tp 37
R28
R27
R26
R25
R24
-40
-60
-80
-100
-120
-60
-100
-80
-100
-80
0km
5km
10km
Contour Interval= 10 m

Fig. 3 - Structure contour map on the pre-Cretaceous unconformity.


MANITOU LAKE
Tp 43
Tp 42
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Tp 37
R28
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R24
1.0
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3.0
4.0
3.0
2.0
1.0
0km
5km
10km
Contour Interval=1.0m
☐ denotes coal > 2.0m

Fig. 4 - Isopach map of the Cummings coal.

MACROSCOPIC CHARACTER

The Cummings coal is a humic or banded coal; in a vertical or cored section through the coal seam, horizontal bands with a minimum thickness of 1 cm are recognizable. The bands are characterized according to Diessel (1965), as thinly banded and banded coal lithotypes (Table 1) with occasional intercalations of banded bright coal. The thinly banded and banded lithotypes range from 1 cm to 5 cm in thickness, whereas the bright banded coal rarely exceeds 0.5 cm.

Divisions as used for Cummings Coal	Description
Bright coal	Subvitreous to vitreous lustre, or conchoidal fracture 10 per cent dull coal.
Banded bright coal	Bright coal with some thin dull bands 10-40 per cent dull coal.
Banded coal	Bright and dull coal bands in equal proportion 40-60 per cent dull coal.
Banded dull coal	Dull coal with some thin bright bands 10-40 per cent bright coal.
Dull coal	Matt lustre, uneven fracture 10 per cent bright coal.
Fibrous coal	Satin lustre, friable 100 per cent fibrous coal.

Table 1 - Descriptions of brown coal lithotypes, according to Diessel (1965), modified.

In the Senlac Field, the seam varies from 280 cm to 370 cm in thickness. It is characterized by finely striated, banded coal, with occasional bright coal lenses and fibrous coal laminae. Numerous carbonaceous shale partings occur throughout the seam; the ratio of coal: clastic partings is 2:1.

In the North Senlac area, the seam ranges from 60 cm to 110 cm in thickness. It consists of finely striated, banded coal with fewer bright coal bands than in the Senlac Field. There are fewer carbonaceous shale partings in the coal than there are in the Senlac area; the ratio of coal: clastic partings is 2.5:1.

In the Winter Field the seam is similar to that of North Senlac. It is reasonably thick (150 to 170 cm) and it comprises finely striated, banded coal; bright coal is virtually absent and bands of fibrous coal are less common than in the Senlac Field. Like the seam in the North Senlac area are there are few clastic partings; the ratio of coal: clastic partings is 1:3.

MICROSCOPIC CHARACTER

The microscropic constituents of the Cummings coal are characterized according to the International Committee for Coal Petrology (1971) (Table 2), coal rank determinations are based on measured heating values and vitrinite reflectance measurements (Fig. 5).

The maceral composition and reflectance data of coals from the Senlac, North Senlac and Winter Fields are shown in Table 3. Regional variations in maceral composition are represented by triangular plots of huminite-liptinite-inertinite and mineral matter (Fig. 6). The petrographic characteristics will be described in terms of regional variation in huminite, liptinite, inertinite macerals and mineral matter.

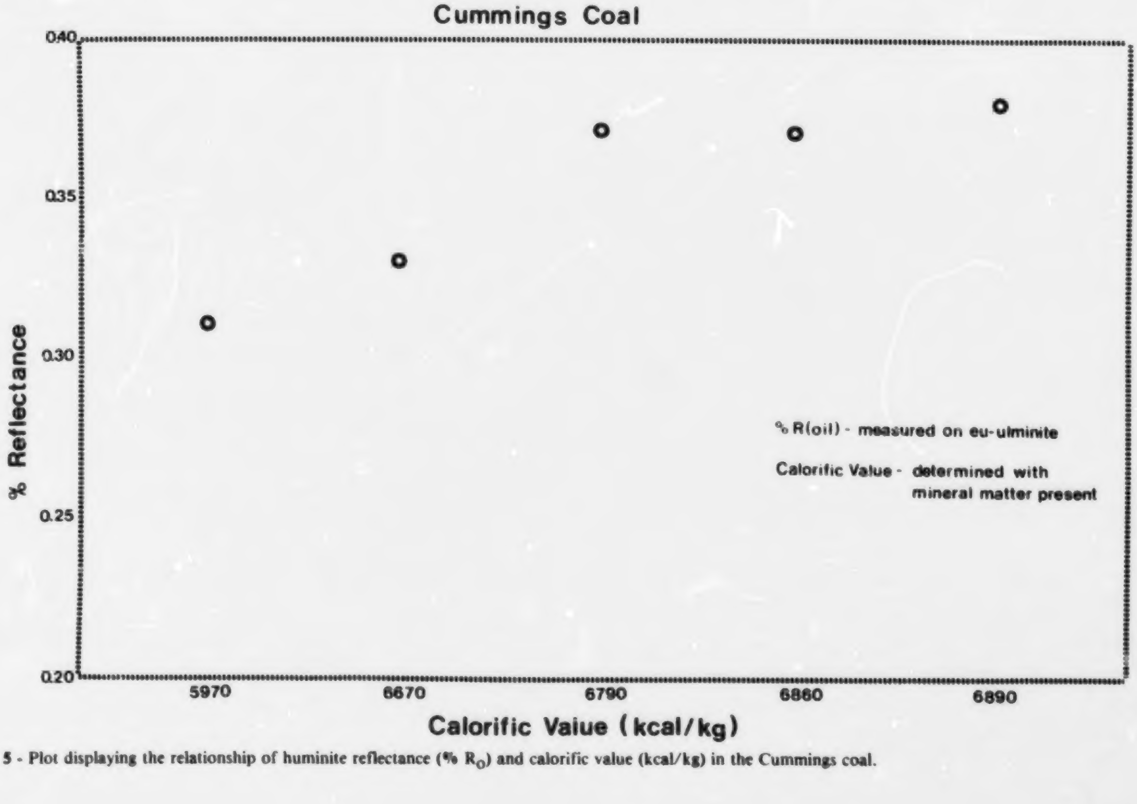

Fig. 5 - Plot displaying the relationship of huminite reflectance (% R_O) and calorific value (kcal/kg) in the Cummings coal.

MACERAL GROUP	MACERAL (I.C.C.P. 1971)	ORIGIN	PETROLOGICAL FEATURES
HUMINITE	Textinite	woody tissue	primary cell wall structure still distinguishable, cell lumina mostly open
	Ulminite	wood tissue	higher degree of humification; *texto-ulminite* - cell wall structure still visible, *eu-ulminite*. No visible cell structure, cell lumina mostly closed
	Attrinite	finely communited	particle size<10 µm more tightly packed
	Densinite	degradation product of the other huminite macerals	more tightly packed than attrinite
	Gelinite	derived from colloidal humic solutions which migrate into existing cavities and precipitate as gels	secondary cell filling
	Corpohuminite	condensation products or tannins, characeteristic for bark tissues	in cross-section globular to tabular shaped
LIPTINITE	Sporinite	pollen, spores	individual bodies with distinct cell walls, high relief
	Cutinite	cuticles	serrated edges, high relief
	Alginite	algae	individual bodies or colonies, high relief
	Resinite	resin, waxes	secondary cell-filling, often zonaton and internal reflections
	Suberinite	bark tisues	cell wall material associated with pholbaphinite
	Liptodetrinite	degradation product of liptinitic macerals	
	Bituminite	uncertain, probably decomposition product of algae, animal plankton, and bacterial lipids	no definite shape, groundmass for other macerals, weak flourescence, strong alteration after UV-excitation
	Chlorophyllinite	pigments of the chlorophyll group, their decomposition products	small round particles, red Flourescence
INERTINITE	Fusinite	woody tissue	high reflectance, colour white to yellowish, open cell lumina, thin cell walls
	Semifusinite	woody tissue	reflectance between huminite and fusinite, small cell lumina or closed, often cloudy appearance, anisotropic
	Macrinite	uncertain, probably formed through oxidation of gelified plant materials	amorphous bodies of irregular shape, high reflectance
	Micrinite	secondary maceral, genesis in part related to occurrence of liptinite macerals	small size, ca. 1µm, granular appearance, high relfectance
	Sclerotinite	fungal mycelia, fungal spores	cellular structure, high reflectance
	Inertodetrinite	Fragments of other inertinite macerals (normally < 30 µm)	

Table 2 - Petrographic characteristics of brown coal macerals (modified from Bustin *et al.*, 1983)

Huminite Macerals

Eu-ulminite is the most abundant of the huminite macerals; it is characterised by cellular structure which has become gelified during biochemical alteration of the peat. The coal in the Senlac Field is richest in eu-ulminite (40.0% - 89.7%), followed by North Senlac (52.0% - 79.7%) and Winter (19.7% - 49.7%).

The rare occurrence of ungelified, cellular structured macerals, textinite and texto-ulminite, attests to intense bacterial decay of the vegetation in the peat stage. This is typical of well-aerated peat forming environments where high alkalinity and Eh promote bacterial activity (Stach, 1983).

The most commonly occurring huminite maceral, densinite (Fig. 7a), forms a groundmass for other macerals (with the exception of cell structured huminite). It comprises detrital huminite (<10 µm) enclosing inertinites, liptinite and unstructured huminite macerals. It also shows signs of extensive gelification, as evidenced by an abundance of levigelinite (Fig. 7b).

Of the twenty four coals studied which have similar huminite contents, the percentage of eu-ulminite is inversely proportional to that of densinite. (In the Winter Field, the coal averages 52.6% densinite, in North Senlac, 23.5% and in the Senlac Field, 18.9%). This suggests that coal in the Winter Field is more detrital in origin while the coal from North Senlac and Senlac areas formed predominantly from *in situ* vegetation. Unstructured huminite macerals (corpohuminite and levigelinite) are relatively abundant in the Cummings coal. Levigelinite occurs as a binder within densinite (Fig. 7b). Corpohuminite (humified cell excretions) range from angular and

		Senlac Field							
		1-6-39-26W3			3-7-39-26W3		4-1-39-27W3		
Maceral Group	Maceral (%)	#1	#2	#3	#1	#4	#5	#4	#5
	texto-ulminite	-	-	-	-	-	-	-	-
	eu-ulminite	80.0	89.7	64.4	45.4	40.0	89.7	83.4	72.9
HUMINITE	densinite	14.0	6.7	18.7	35.7	45.4	3.0	3.3	17.1
	corpohuminite	1.0	-	3.0	3.0	2.0	5.7	12.3	5.7
	levigelinite	0.7	-	2.0	5.3	3.0	-	-	0.7
	sporinite	-	0.7	1.7	-	-	-	-	-
	cutinite	-	-	-	0.3	-	-	-	-
	alginite	-	-	-	0.3	-	-	-	-
LIPTINITE	resinite	-	-	-	-	0.7	-	-	-
	liptodetrinite	-	-	-	0.7	0.3	-	-	-
	bituminite	-	-	-	-	-	-	-	-
	chlorophyllinite	-	-	-	-	-	-	-	-
	fusinite	0.3	0.7	0.7	3.0	1.7	-	-	0.3
	semifusinite	0.3	1.0	4.0	1.7	1.3	-	-	0.3
INERTINITE	macrinite	-	-	1.0	0.6	-	-	-	-
	micrinite	-	-	-	-	0.3	0.3	-	-
	sclerotinite	-	-	1.7	-	-	-	-	-
	inertodetrinite	0.7	-	0.4	3.0	4.0	0.3	-	-
	pyrite/marcasite	3.0	1.2	2.4	1.0	1.3	1.0	1.0	3.0
	% reflectance	0.31	-	-		0.34	-	0.34	-

		Winter Field						
		3-29-42-25W3		9-29-42-25W3		10-28-42-25W3		6-7-43-24W3
Maceral Group	Maceral (%)	#1	#5	#4	#5	#1	#2	#1
	texto-ulminite	-	-	-	-	-	-	-
	eu-ulminite	30.3	23.3	49.7	37.0	21.0	19.7	24.4
HUMINITE	densinite	48.7	65.7	35.3	48.3	58.2	60.3	51.7
	corpohuminite	3.3	2.0	5.7	5.7	6.0	8.7	0.3
	levigelinite	6.7	3.7	6.0	4.7	7.3	7.7	3.7
	sporinite	0.3	1.0	0.7	1.0	0.3	0.3	0.3
	cutinite	0.7	0.3		-	0.3	-	0.3
	alginite	-	-	0.3	-	0.3	-	0.3
LIPTINITE	resinite	2.0	0.3	-	-	1.3	0.3	0.7
	liptodetrinite	-	-	-	-		-	-
	bituminite	-	-	-	-	-	-	-
	chlorophyllinite	-	-	-	-	-	-	-
	fusinite	3.0	-	-	0.3	1.3	-	8.7
	semifusinite	0.3	-	-	0.3	0.7	-	3.3
INERTINITE	macrinite	0.7		-	0.3	0.6	-	-
	micrinite	-	-	0.7	-	-		0.3
	sclerotinite	-	-	-	-	-	0.3	
	inertodetrinite	2.0			2.0	1.0	-	4.3
	pyrite/marcasite	1.3	3.3	1.6	0.4	1.0	2.0	0.7
	% reflectance	0.38		0.31			0.31	0.31

		North Senlac Area								
		2-21-40-26W3		11-7-40-25W3		14-3-40-26W3	10-4-40-26W3	14-32-39-26W3		
Maceral Group	Maceral (%)	#1	#5	#1	#2	#1	#1	#1	#1A	#2
	texto-ulminite	0.3	-	0.6	-	-	0.7		0.7	-
	eu-ulminite	52.0	75.4	52.3	77.3	45.0	22.3	51.2	12.3	79.7
HUMINITE	densinite	30.4	8.7	22.0	10.3	38.0	38.6	12.4	36.7	14.3
	corpohuminite	2.0	0.3	0.3	1.0	2.0	-	-	0.3	0.7
	levigelinite	5.3	1.0	- -	0.7	4.3	1.3	0.6	02.3	2.0
	sporinite	-	0.3	0.6	1.0	0.7	-	0.6	1.0	
	cutinite	-	0.3		0.3	0.3	-	-	0.7	
	alginite	1.7	-		0.3	2.7	0.7	-	-	
LIPTINITE	resinite	-	-	-	0.7	-	-	2.3	1.3	0.3
	liptodetrinite	0.3	1.0	0.3	0.7	1.0	0.7	1.6	1.0	-
	bituminite	-	2.0		-	-	-	-	-	
	chlorophyllinite	-			-		-		-	
	fusinite	1.7	0.7	3.0	2.4	1.0	16.0	4.9	13.7	0.7
	semifusinite	1.3	0.7	3.3	2.0	1.7	7.6	14.2	14.0	0.3
INERTINITE	macrinite	0.3	1.3	0.6	0.3	-	3.4	3.3	1.0	
	micrinite	-	-	-	-	-	-	-	1.7	-
	sclerotinite		-		-		-	-	-	-
	inertodetrinite	1.0	8.3	2.3	1.0	1.0	2.7	6.0	9.3	-
	pyrite/marcasite	3.7	-	14.7	2.0	2.3	6.0	2.9	4.0	2.0
	% reflectance	-	0.31	0.37		0.37	0.34	0.33		

Table 3 - Maceral composition and reflectance data for the Cummings coal, Winter, Senlac and North Senlac areas.

subangular phlobaphenite bodies to spherical and elliptical forms, hosted by densinite (Fig. 7b). In the Winter field, levigelinite and corpohuminite average 10.2% of the total coal; in Senlac they average 4.6% and in North Senlac, the mean values are 2.7%.

Inertinite Macerals

The inertinite contents of the 24 samples are similar (0% to 11.0%); four anomalous values (16.6%, Winter field; 29.7%, 39.7% and 28.4%, North Senlac area) were recorded. The dominant forms, inertodetrinite (reworked or detritial fusinite) and semifusinite (charred or oxidized wood) are associated with densinite and fusinite semifusinite and fusinite are the principal constituents of the fibrous coal bands. Macrinite and semi-macrinite are common inclusions in densinite. Micrinite is commonly associated with a liptinite maceral, resinite (Fig. 7c), but in general, it is rare in the Cummings coal.

Liptinite Macerals

Most liptinite macerals, except for suberinite, are present in the Cummings coal (Table 2). They occur in modest amounts (0% - 4.7%) mostly in densinite, associated with levigelinite. Alginite, inlcuding *Botryococcus* (Fig. 7d), was identified in samples from the Winter field. Unidentified alginite occurs in samples from the Winter Field and North Senlac. Chlorophyllinite (Fig. 7e), occurs in 12 of the samples and in all three areas. Resinite occurs as infillings in inertinite and impregnating porous densinite. Bituminite (Fig. 7f) is present in minor quantities in coals from the North Senlac area. Migrabitumen (Jacob, 1983) is not found in the coal itself but occurs in carbonaceous shale partings within the coal (Fig. 7g); its source may be the heavy oil from the overlying sand reservoirs.

Mineral Matter

Petrographically identified mineral matter in the Cummings coal comprises pyrite and marcasite, finely dispersed clay minerals and sub-µm sized quartz. The pyrite/marcasite forms occur as euhedral crystals (<5 µm), framboids and in massive form replacing original plant material (Fig. 7h).

Framboids 25 µm in diameter (some coalescing), show zoning of pyrite and marcasite (Fig. 7i); commonly these occur in densinite. Framboids <25 µm are pyritic. Mostly these are primary and occur in eu-ulminite. In the latter, case, the size and mineralogy were probably controlled by the pH of the water in the peat forming environment.

Coal rank

Reflectance determined on 12 samples ranges from 0.31% -0.38%, Ro random; this is enough to indicate that the coal is of sub-bituminous rank. Heating value (calorific value) determined for 5 coal samples, ranges from 5800 kcal/kg to 6900 kcal/kg and average 6445 kcal/kg. Figure 5 shows the relationship betwen the huminite reflectance and the calorific value.

DEPOSITIONAL ENVIRONMENT

DINA AND CUMMINGS FORMATIONS

Palynological samples are characterized by considering arbitrary levels of marine and continental palynomorphs as indicators of proximity to coastal depositional environments. In the Winter Field, the overall percentage of marine palynomorphs (average: 10%) is considerably higher than at Senlac (average: 4%). In modern sediments in California, Cross, Thompson and Zaitzeff (1977) demonstrated an increase in dinoflagelates away from the shore. Similar trends in the Winter-Senlac area suggests a greater marine influence on sediments towards the north in Lower Mannville time.

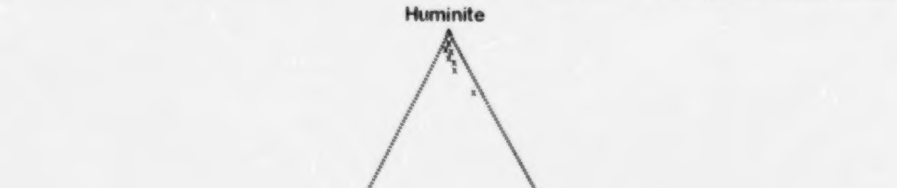

Fig. 6 - Triangular plots of huminite - liptinite - inertinite and mineral displaying the regional variations between coals in the Senlac, North Senlac and Winter areas.

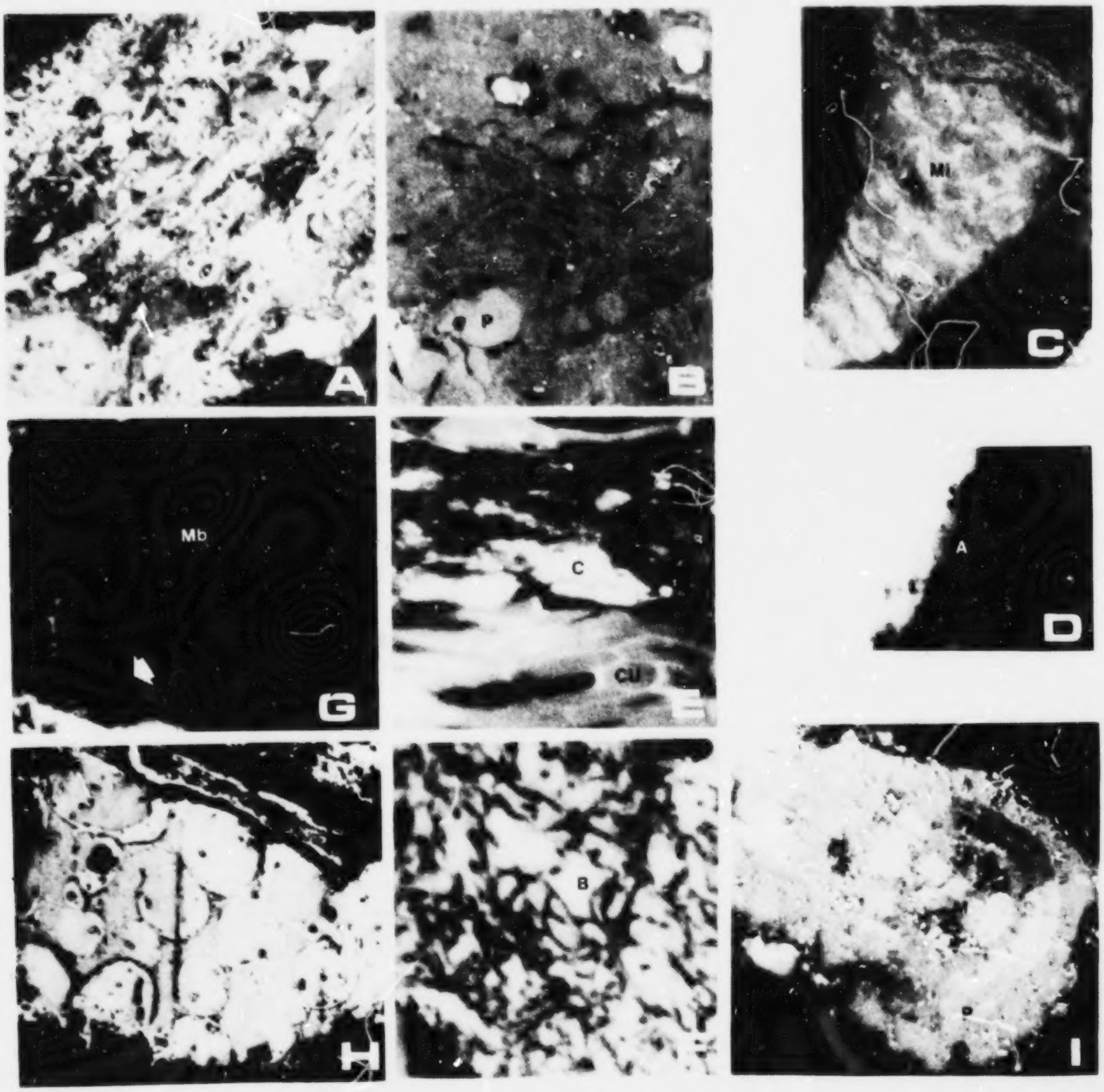

Fig. 7A - Densinite hosting inertinites. Cummings coal, North Senlac area. (Lsd. 14-32-39-26W3; oil immesion, plane polarized, reflected light, X1000).

Fig. 7B - Gelinite (G) and phlobaphenite (P) within extensively gelified densinite. (Lsd. 10-28-42-25W3; oil immersion, plane polarized, reflected light, X1000).

Fig. 7C - Micrinite (Mi) and resinite (R) impregnation of structured huminite. (Lsd. 14-32-39-26W3; oil immersion, plane polarized, reflected light, X1000).

Fig. 7D - Alginite (A) derived from *Botryococcus*. (Lsd. 3-29-42-25W3; oil immersion, blue-light excitation, X2000).

Fig. 7E - Chlorophyllinite (C) probably originating from the same parent material as the cutinite (CU). (Lsd. 14-3-40-26W3; oil immersion, blue-light excitation, X2000).

Fig. 7F - Bituminite (B), maceral, from the Winter Field. (Lsd. 3-29-42-25W3; 1 immersion, bluelight excitation, X1000).

Fig. 7G - Carbonaceous shale parting in the coal from the Winter Field often contain migrabitumen (Mb). Dark spots (indicated by the arrow) are reaction zones from blue-light excitation. (Lsd. 3-29-42-25W3; oil immesion, blue-light excitation, X1000).

Fig. 7H - Syngenetic pyrite which has replaced organic matter: the globular structure of the original organic matter has been preserved by mineralization (Lsd. 9-29-42-25W3; oil immersion, plane polarized light, X1000).

Fig. 7I - Radial structure typical of marcasite framboids (M) with pyrite (P) overgrowth. (Lsd. 14-32-29-26W3; oil immersion, plane polarized light, ½ crossed polars, X1000).

Sedimentological studies of Dina/Cummings sediments suggest that north and northwesterly flowing fluvial channels, draining the nearby carbonate highlands, probably deposited the basal Dina sand. The linear sand body at Senlac is thought to have been deposited by a northward flowing river that was confined to the paleovalley. The North Senlac linear sand appears to have resulted from deposition in a fluvial channel that flowed westward along the nose of the Paleozoic ridge.

The thickest sands are situated in an area where, it is proposed, the two channels met. Off-channel sediments cored at North Senlac are an undifferentiated series of organic rich, overbank muds and rippled crevasse-splay sands. Throughout the northwest, the Dina sand becomes more widespread, reaching a maximum thickness of 27 m in Township 43 Range 28. The overall trend of the sand is consistent with Gross' (1980) mapping of an extensive Dina valley-fill deposit extending eastward from Alberta.

Cessation of Dina valley-fill deposition began with the transgression of the Clearwater sea from the north or northwest. The Battleford arch remained a prominent structural feature, limiting the southern extent of the transgression and subsequently, deposition of the Cummings Formation (Fig. 1). In the Senlac Field, the pinstripe bedding that characterizes the upper Cummings sediments, is indicative of a high intertidal mud flat environment (Rief and Siatt, 1979). The paucity of marine palynomorphs suggests the area was still highly influenced by fluvial waters causing fresh water dilution. North Senlac is situated within a belt of mixed sand and mud flat sediments, approximately 10 km wide, that roughly parallels the Battleford arch. Cores of the Cummings Formation in "off-channel" wells are characterized by numerous coarsening-upward, bioturbated, crevasse-splay deposits. The marine portions of the thicker sands are thought to be the result of deposition in small tidal channels or small estuaries.

The Cummings Formation across the central and western parts of the study area represents a relatively high energy environment. Along the western border, thin beach sands cap a coarsening-upward sequence, pinch out eastward, and are replaced by a silty sand of the lower intertidal sand flat. This silty sand also thins towards the east and grades into interbedded sediments of the mixed sand and mud flat.

In the Winter Field, the presence of the intraformational conglomerate, is strong evidence for channeling (Ruby, Horne and Reinhart, 1981), which, together with the palynological interpretation of a marine origin for the sands, suggests that the majority of the sand interval was deposited by a tidal channel. The conglomerate is similar to the channel-bank collapse facies reported by MacEachern (this volume) which provides evidence of lateral migration. The tidal channel was confined to the east along a southwest trending ridge within the Battleford arch; channel margin shales delineate the boundary. To the west, the extent of channel migration is less well defined as the sands intercalate with a fining-upward interbedded sand and shalesequence.

The well elutriated nature of the upper part of the sand in the Winter Field is inconsistent with the silty, fining-upward character of most of the channel sands to the north. It is evident that some degree of wave influence, combined with tidal processes, acted to winnow out interstitial fines. The appearance of swash-zone cross-lamination near the top of the sand in some cores, suggests the possibilty of beach-type processes (Harms, Southard and Walker, 1982). A thick shale bed in well 10-28-42-25W3, is interpreted as part of the channel margin sediments and attests to the proximity of the Winter sand to the channel margin, for at least the upper part of its depositional history.

The coal is underlain by 1-2 m of rooted underclay and varying thicknesses of fining-upward interbedded intertidal sediments. This sequence is evidence of a marine regression (probably local) that resulted in emergence and colonization by terrestial vegetation.

CUMMINGS COAL

Several inferences regarding the environment of peat formation can be made, on the basis of the macroscropic and microscopic characters of the coal.

The finely banded or humic character of the coal firstly attests to the autochthonicity of peats forming in low lying areas with a relatively high water table. Thick clastic partings in the coaly interval in the Winter Field reflect an increase in the groundwater table in the peat forming environment, during which, the peat became buried by clastic sediments. The peat swamps subsequently re-established themselves during tectonically stable periods. Stach (1983) suggests that the formation of carbonaceous shale partings requires considerably greater water depth than any coal lithotype.

Senlac Field

In the Senlac Field, structured huminites are the dominant coal macerals, which indicates that the coals in the Senlac area formed *in situ*, from woody plants of coastal swamps. Their well preserved cell structures suggest that the peat swamps were relatively acidic, thereby restricting the degree of microbial degradation of vegetal matter. According to Styan and Bustin (1983), restricted bacterial and fungal activity results in higher ratios of huminitic framework (eu-ulminite) to matrix (densinite); this is characteristic of the coal in the Senlac Field. The precursor of the eu-ulminite in the Cummings coal was probably conifer wood; phlobaphenitic cell inclusions, typical of fossil conifers (I.C.C.P., 1971), and gymnosperm wood structure, in fusinite and semifusinite, were observed. Furthermore, the densinite hosts minute amounts of sporinite, which is typical of coals/peat formed in tree dominated swamps (Teichmuller, 1982) and 25% of all palynomorph assemblages comprise conifer saccate grains.

The absence of abundant framboidal pyrite and the occurrence of finely disseminated euhedral pyrite strongly suggests that there was little marine influence on the coastal swamps in this area.

Winter Field

The dominant maceral in the Cummings coal of the Winter Field is detrital densinite which is impregnated with unstructured levigelinite. Coals of this nature, as Styan and Bustin (1983) have shown, are typically derived from grass dominated marshes. It is likely, therefore, that coal in the Winter Field formed from marsh peats rather than swamp peats. Furthermore, the presence of massive levigelinite is evidence of strong decomposition of humic substances such as occurs in alkaline media (Stach, 1983). Alginites, derived from fresh water algae such as *Botryococcus*, are present and cutinite, generally preserved in subquatic conditions, is common. Chlorophyllinite is consistently present as a minor component. It derives from chlorophyll and is only preserved as a coal maceral under strongly anaerobic conditions in moderate to cool climates (I.C.C.P., 1971). Futhermore Hodgson and Hitchon (1959) noted that chlorophyll is most favorably preserved in slightly alkaline to alkaline environments in the presence of calcium carbonate.

In contrast to the coal in the Senlac Field, framboidal pyrite is common in the Winter Field, although disseminated pyrite/marcasite euhedra are also present. Syngenetic framboidal pyrite is characteristically formed in marine influenced peat where marshes are being transgressed by marine to brackish-water environments (Horne *et al.*, 1978) or in calcium-rich swamps (Casagrande *et al.*, 1977).

North Senlac

Petrographic analysis of the Cummings coal in the North Senlac area reveals two distinctive coal types. One type of coal resembles the Senlac coal and therefore represents tree dominated coal swamps while the other resembles Winter coal, and probably derives from coastal grass dominated marshes.

Bituminite is unique to North Senlac coal and is a common component of sapropelitic coal. It is produced by intense degradation of aquatic plants and algal detritus which is commonly incorporated in subaquatic muds.

Sulphur

Table 4 shows the abundance and distribution of sulphur in the Cummings coal. The high values or organic sulphur are uncharacteristic of coal in North America. Kreulen (1952) reports up to 8% organic sulphur in the Rasa coal of Istria, Yugoslavia, and Suggate (1959) shows that many of the Cretaceous and Tertiary coals of New Zealand have organic sulphur contents up to 9%. Both these coals are intimately associated with marine sediments and Suggate (1959) suggests a marine origin for the organic sulphur.

DISCUSSION

The petroleum industry assigns the whole basal sand unit of the Lower Mannville Group to the Dina Formation. Vigrass (1977) considers that, in some places, this sand unit comprises the Dina Formation and basal Cummings Formation and that the boundary is diachronous. The authors agree with Vigrass; we interpret the Dina sediments as fluvial, paleovalley-fill sands while the Cummings sands are marine.

The linear sands (Dina Formation) of the Senlac and North Senlac areas, which we have interpreted as valley-fill deposits, are considerably thinner and narrower than those proposed by Gross (1980). They are, however, similar to paleovalley-fill sands in Pennsylvania which display a shoestring geometry (Lyons and Dobrin, 1972). In the Winter Field it is suggested that Dina beds, being thin or absent near Paleozoic highs, may also have been affected by tidal channel reworking. According to Reineck and Singh (1980) tidal channels can rework underlying sediments to depths greater than 6 m. Some sedimentary structures characteristically associated with tidal channels, e.g. herring-bone cross-stratification, reactivation surfaces and cross-stratification with sharp set boundaries (Klein, 1971), appear to be absent; they may simply be masked by the heavy oil saturation.

The high levels of organic sulphur in the Cummings coal are thought to be derived from or a combination of: 1) sulphide ions, produced by the reduction of sulphate, which are incorporated into organic compounds in the absence of reactive iron (Neavel, 1966), 2) abstraction and migration of sulphur from the overlying heavy oil sands (the presence of migrabitumen (Fig. 7g) suggests that there may have been some migration of heavy oil constituents into the coal), or 3) high sulphur values in the original peat forming flora.

Speculations about the Early Cretaceous paleogeography by McLean and Wall (1981) and Williams (1963), indicate that the transgressing Clearwater sea followed old river-valley systems creating large estuaries. Such an estuary extended from central Alberta to the Winter-Senlac area, according to McLean and Wall (1981). The valley-fill and tidal flat environments proposed for the Dina and Cummings Formations therefore appear to be consistent with this regional setting for the Lower Mannville. It is likely that the Cummings coal formed in a coastal plain environment similar to that described by Bustin *et al.*, (1983) and proposed by Gibson (1977) for a carbonaceous coaly facies in the Crowsnest Pass area of southwestern Alberta and southeastern British Columbia.

Since coalification and petroleum genesis, are to some extent, controlled by similar diagenetic factors (temperature and time), levels of petroleum source rock maturation can generally be matched with coal rank, as determined by vitrinite reflectance. The Cummings coal is a sub-bituminous coal, having a measured reflectance (R_O random) of 0.30% to 0.38%. Organic matter in sediments with a vitrinite reflectance ranging

Area	Well Location	Sample	Total S (wt.%)	Sulphate (wt.%)	Pyritic (wt.%)	Organic (wt.%)
Winter	9-29-42-25W3	#7	9.49	0.15	0.76	8.58
		#5	9.45	0.12	0.77	8.56
		#4	10.32	0.14	0.86	9.32
	3-29-42-25W3	#2	8.97	0.27	1.13	7.39
		#4	10.13	0.49	0.56	9.08
	10-28-42-25W3	#1	10.82	0.18	0.70	9.94
		#2	9.80	0.12	0.98	8.70
Senlac	4-1-39-27W3	#3	5.34	0.09	1.44	3.81
		#1	6.16	0.14	1.95	4.07
	3-7-39-26W3	#4	5.76	0.15	1.96	3.65
		#1	4.38	0.06	0.28	4.04
North Senlac	2-21-40-26W3	#2	5.62	0.11	1.76	3.75
		#1	4.79	0.09	0.63	4.07
	14-3-40-26W3	#1	12.11	0.30	3.68	8.13

Table 4 - Sulphur analyses of Cummings coal, Winter, Senlac and North Senlac areas.

from 0.55% to 1.3% R_O max., is known to generate oil (Stach, 1983). The Cummings coal would therefore appear to be an unlikely source for Lower Cretaceous oil.

CONCLUSIONS

1. The paleopositve relief of the Battleford arch, and its associated ridge, has largely controlled the distribution of Dina and Cummings Formations, including the Cummings coal.
2. The Dina Formation is a fluvial deposit confined to relatively narrow channels by the erosional relief on the pre-Cretaceous unconformity in the Senlac Field. It expands across a broad flood plain as a valley-fill sand in the west of the North Senlac and Winter areas.
3. The Cummings Formation was deposited in a nearshore environment; it is characterized by shallow marine sediments grading into upper tidal flat sediments along the Battleford arch, and tidal channel sediments to the north.
4. The macroscopic and microscopic character of the Cummings coal indicates that it formed from peat swamp and marsh vegetation in a marginal marine setting. The predominance of detrital coal in the Winter Field as opposed to intensely biochemically altered, non-detrital coal in the Senlac Field suggests that while fluvial water affected peat swamps in the south, the peat marshes to the north came under marine influence. A decrease in the abundance of marine palynomorphs from north to south is strong evidence of the predominance of marine conditions in the Winter area.
5. The Cummings coal contains an anomalously high percentage of sulphur; the majority of it is organic sulphur.

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DISTRIBUTION OF THE SPARKY FORMATION HEAVY OIL FIELDS WITHIN THE LLOYDMINSTER SUB—BASIN

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Husky Oil Operations Ltd.
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ABSTRACT

Heavy oil in the Lloydminster area of Saskatchewan and Alberta is produced from the Lower Cretaceous Mannville Group, of which the Sparky formation is one of the most significant oil-bearing formations. Pre-Cretaceous high areas, termed the Baldwinton Ridge to the south, Wainwright Ridge to the southwest and Lindbergh Ridge to the north, form the limits of the Lloydminster Sub-basin. A structural depression to the east and northeast was caused by salt disolution of the Devonian Prairie Formation. Deposition of the Sparky formation has been influenced by the configuration of the Lloydminster Sub-Basin.

The Sparky formation can be subdivided into two major facies: Regional and Channel. Its characteristics suggest deposition within a wave-dominated deltaic system. Sandstones of the Regional Facies contain most of the heavy oil accumulations and can be up to 14m thick. The Channel Facies, which is predominantly shale-filled, locally develops excellent reservoir sandstones up to 40m thick.

The major Sparky formation heavy oil accumulations are situated in the central portion of the Lloydminster Sub-basin. Major oil fields include Aberfeldy, Epping, Golden Lake, Celtic, Westhazel, Marsden, Blackfoot and Wainwright. Four types of traps are recognized:

(A) Regional Facies sandstones abutting against shale-filled Channel Facies,
(B) Regional and Channel Facies sandstones trapped structurally; mainly due to salt dissolution of the Devonian Prairie Formation,
(C) Sandstones locally developed within the Channel Facies,
(D) Lateral pinch-out of the Regional Facies sandstones.

INTRODUCTION

The Lloydminster heavy oil area of Saskatchewan and Alberta (Fig. 1) contains an estimated total of 8 to 11 billion m^3 (50 to 69 billion barrels) of oil in place[1]. New development drilling could add an additional 16 million m^3 (102 million barrels) of reserves while existing and new enhanced oil recovery (EOR) projects expect to increase the reserve base by approximately 43 million m^3 (272 million barrels)[1]. Approximately sixty percent of the oil in place occurs within the Sparky formation of the Lower Cretaceous Mannville Group (Orr *et al.*, 1977).

The study area encloses Twps. 42-54, Rges. 17-28 W3M and Rges. 1-7 W4M and contains all the major Lloydminster heavy oil fields. The major Sparky oil pools and fields are depicted in Figure 2. Approximately 12,000 wells have been drilled in the Lloydminster area and most of these wells penetrate the Sparky formation.

The purpose of this paper is to:

(a) outline the major structural elements of the Lloydminster Sub-basin,
(b) relate regional depositional characteristics of the Sparky formation to the Lloydminster Sub-basin,
(c) illustrate the major hydrocarbon trapping mechanisms for the Sparky formation.

STRATIGRAPHY OF THE MANNVILLE GROUP

The Lower Cretaceous Mannville Group is a series of very fine to fine grained sandstone, siltstone, shale, and coal beds which unconformably overlie eroded Paleozoic carbonates and are overlain by marine shales of the Joli Fou Formation of the Colorado Group (Vigrass, 1977). The most commonly used stratigraphic nomenclature for the Mannville Group was described by Vigrass (1977) and Orr *et al.* (1977). They both used the same nine informal stratigraphic subdivisions (Fig. 3) except that Vigrass called them members whereas Orr *et al.* refer to them as formations. Both of them placed the stratigraphic contacts at the top of the sandstones. MacCallum (1979) initiated the use of shale and coal marker beds to define these boundaries. The present authors believe the Mannville Group can be subdivided into correlatable subdivisions in the Lloydminster area based on regional marker beds, so these subdivisions should be referred to as formations.

BASIN CONFIGURATION

The Sparky formation (Figs. 4 and 5) and other Mannville formations have a regional southwesterly dip of approximately 1.9m/km which is probably associated with the Laramide Orogeny (Christopher, 1980). The Sweetgrass Arch extends into the Lloydminster area with the Alberta Basin to the west and the Williston Basin to the southeast (Stelck, 1975) (Fig. 1).

The major structural elements forming the boundaries of the Cretaceous Lloydminster Sub-basin (Orr *et al.*, 1977) are illustrated on the Base of Fish Scale Zone to pre-Cretaceous unconformity surface isopach map (Fig. 6). The second order residual map of the pre-Cretaceous unconformity surface (Fig. 7) depicts structural highs where the isopach map shows thin areas. These features are termed:

(a) Wainwright Ridge - southwestern limit,
(b) Baldwinton Ridge - southern limit,
(c) Lindbergh Ridge - northern limit.

The Devonian Woodbend Formation in Alberta is approximately stratigraphically equivalent to the Duperow Formation

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[1] Nova and Husky Submission to the National Energy Board (1984): Supply - Demand Forecast.

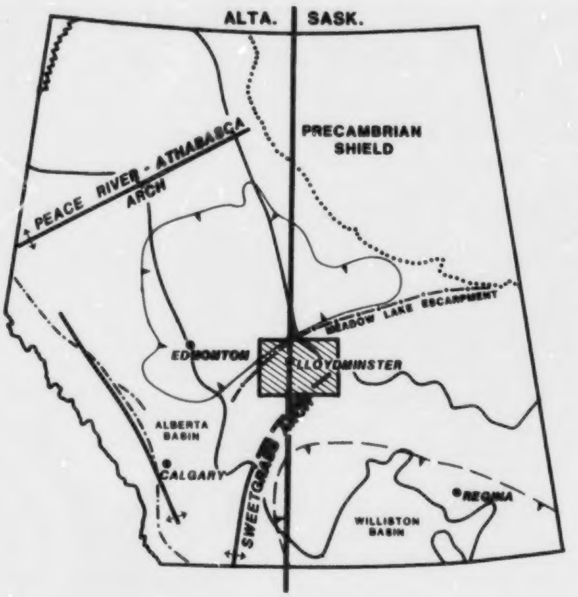

ALTA.
SASK.
PRECAMBRIAN SHIELD
PEACE RIVER - ATHABASCA ARCH
MEADOW LAKE ESCARPMENT
EDMONTON
LLOYDMINSTER
ALBERTA BASIN
CALGARY
SWEETGRASS ARCH
REGINA
WILLISTON BASIN
▨ STUDY AREA
SALT DISTRIBUTION IN DEVONIAN PRAIRIE FORMATION
WILLISTON BASIN EDGE
LOWER ELK POINT "BASIN"
OVERTHRUST BELT

Fig. 1 - Location map indicating the study area and major structural elements. The Meadow Lake Escarpment was an important structural element during the Devonian and coincides with the northwest boundary of the study area. Whether the escarpment played any role during the Cretaceous has not been definitely shown at this time. (Modified after McCrossan and Glaister, 1964; Stelck, 1975).

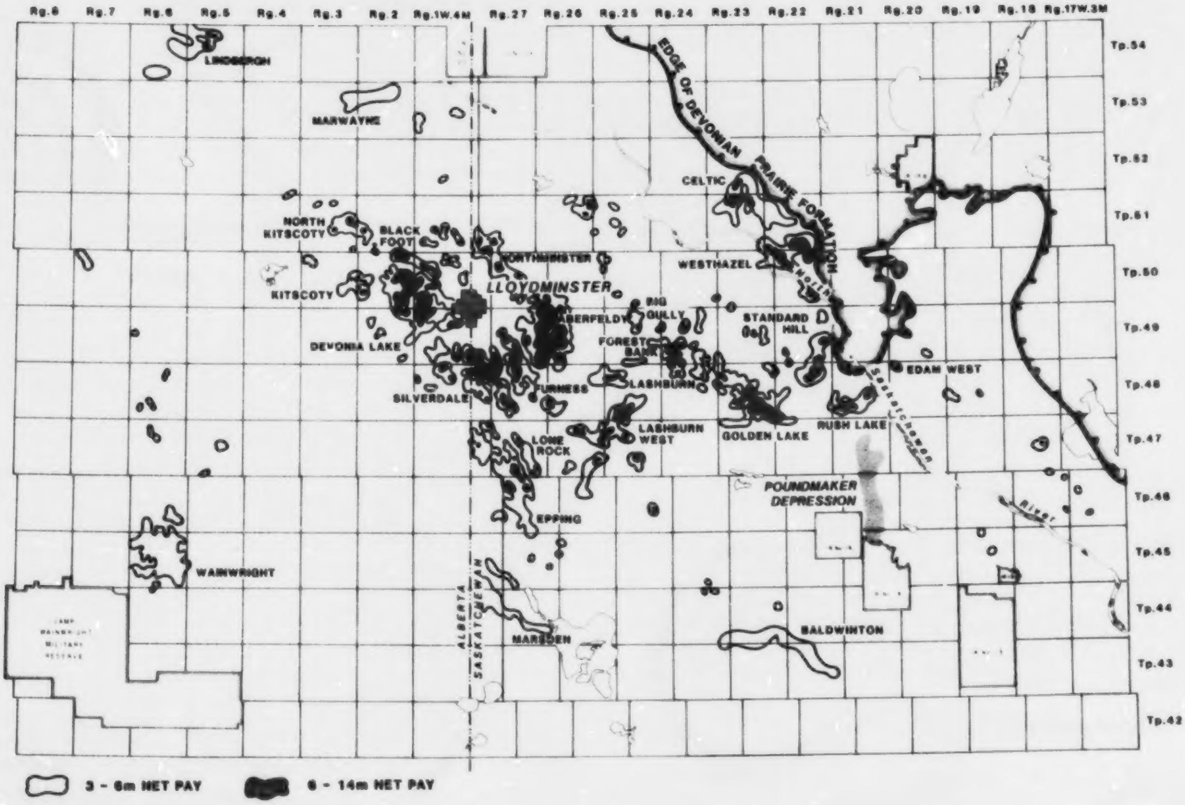

Rg.8
Rg.7
Rg.6
Rg.5
Rg.4
Rg.3
Rg.2
Rg.1W.4M
Rg.27
Rg.26
Rg.25
Rg.24
Rg.23
Rg.22
Rg.21
Rg.20
Rg.19
Rg.18
Rg.17W.3M
Tp.54
Tp.53
Tp.52
Tp.51
Tp.50
Tp.49
Tp.48
Tp.47
Tp.46
Tp.45
Tp.44
Tp.43
Tp.42
LINDBERGH
MARWAYNE
EDGE OF DEVONIAN PRAIRIE FORMATION
CELTIC
NORTH KITSCOTY
BLACK FOOT
NORTHMINSTER
WESTHAZEL
KITSCOTY
LLOYDMINSTER
BIG GULLY
ABERFELDY
STANDARD HILL
DEVONIA LAKE
FOREST BANK
LASHBURN
EDAM WEST
SILVERDALE
FURNESS
North Saskatchewan
LONE ROCK
LASHBURN WEST
GOLDEN LAKE
RUSH LAKE
POUNDMAKER DEPRESSION
EPPING
River
WAINWRIGHT
ALBERTA
SASKATCHEWAN
CAMP WAINWRIGHT MILITARY RESERVE
MARSDEN
BALDWINTON
3 - 6m NET PAY
6 - 14m NET PAY

Fig. 2 - Net pay met for the Sparky formation's Regional Facies showing the major oil fields. Despite the thin reservoir sandstone/siltstone in the Wainwright Field, it is an important Sparky oil field because of its lower viscosity oil.

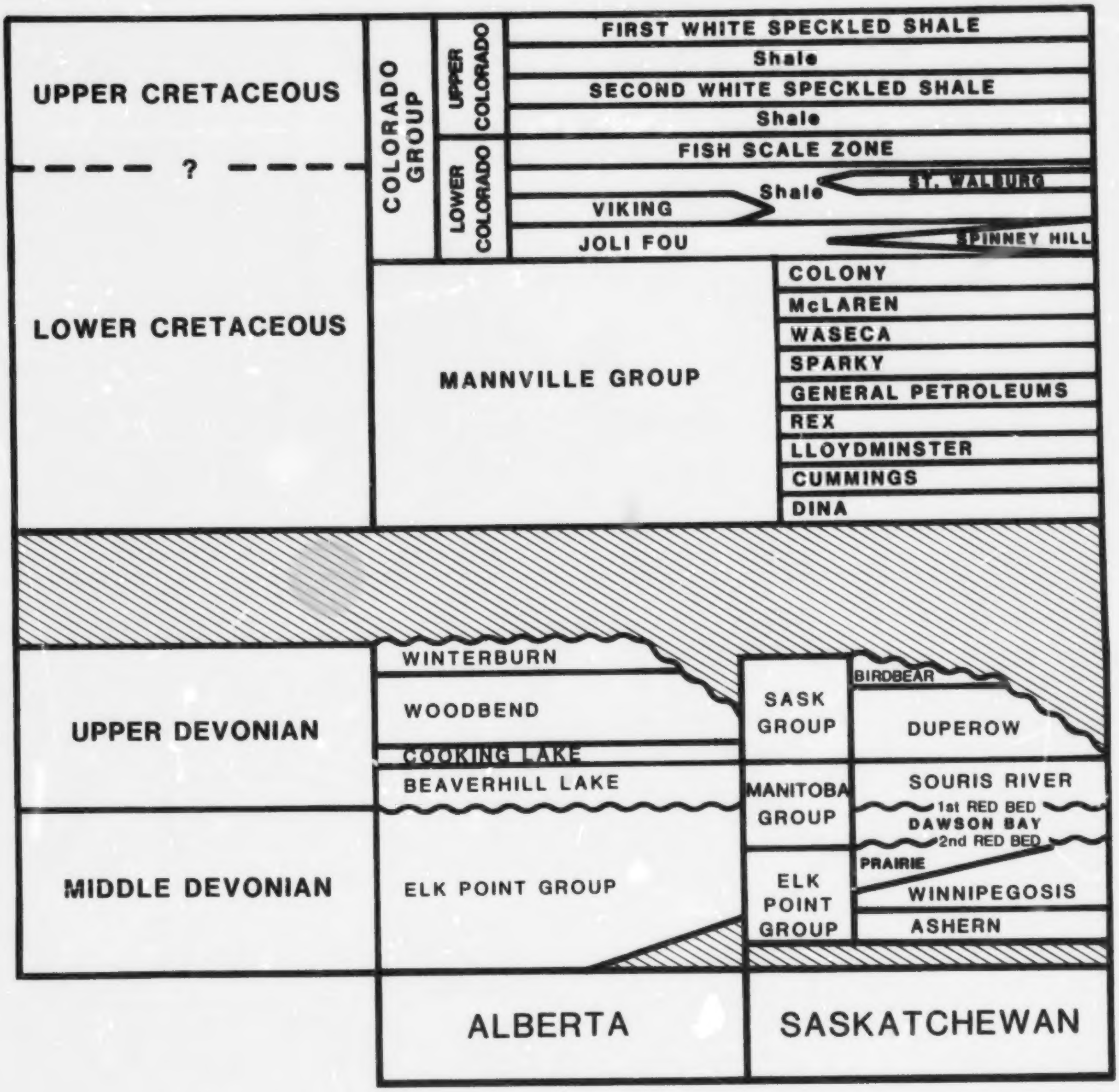

UPPER CRETACEOUS
?
LOWER CRETACEOUS
COLORADO GROUP
UPPER COLORADO
LOWER COLORADO
FIRST WHITE SPECKLED SHALE
Shale
SECOND WHITE SPECKLED SHALE
Shale
FISH SCALE ZONE
Shale
ST. WALBURG
VIKING
JOLI FOU
SPINNEY HILL
MANNVILLE GROUP
COLONY
McLAREN
WASECA
SPARKY
GENERAL PETROLEUMS
REX
LLOYDMINSTER
CUMMINGS
DINA
UPPER DEVONIAN
WINTERBURN
WOODBEND
COOKING LAKE
BEAVERHILL LAKE
SASK GROUP
BIRDBEAR
DUPEROW
MANITOBA GROUP
SOURIS RIVER
1st RED BED
DAWSON BAY
2nd RED BED
MIDDLE DEVONIAN
ELK POINT GROUP
PRAIRIE
ELK POINT GROUP
WINNIPEGOSIS
ASHERN
ALBERTA
SASKATCHEWAN

Fig. 3 - Stratigraphic Nomenclature, Lloydminster Area.

in Saskatchewan and subcrops on the Wainwright, Baldwinton and Lindbergh Ridges (Figs. 4, 5, and 7) (Formation names in parentheses are the Saskatchewan equivalents to the Alberta nomenclature used in this paper). The Devonian Winterburn (Birdbear) Formation also subcrops on the Wainwright Ridge but is absent on the other ridges. The Lindbergh Ridge is less pronounced than the other two ridges with the Woodbend Formation being relatively thin in this area. The Devonian Cooking Lake (lower part of the Duperow) and Beaverhill Lake (Souris River) Formations subcrop in the eastern part of the Lloydminster area. The Wainwright, Baldwinton and Lindberg Ridges separate the Lloydminster Sub-basin from the following areas, respectively: Central Alberta, the Kindersley heavy oil area and the Cold Lake oil sand area.

The Meadow Lake Escarpment (Fig. 1) which was an important structural element during Middle Devonian Lower Elk Point salt deposition, coincides with the northwestern limit of the Lloydminster Sub-basin. Orr *et al.* (1977) found no apparent relationship with Mannville deposition. MacCallum (1979), however, shows that the extent of the Lloyminster formation sandstones coincides with the Meadow Lake Escarpment. The escarpment may, therefore, have had some influence on Mannville deposition.

In the eastern part of the study area, salt dissolution of the Devonian Prairie Formation has resulted in structural reversal of the overlying strata (Figs. 4 and 5). The second order residual map on the pre-Cretaceous unconformity surface

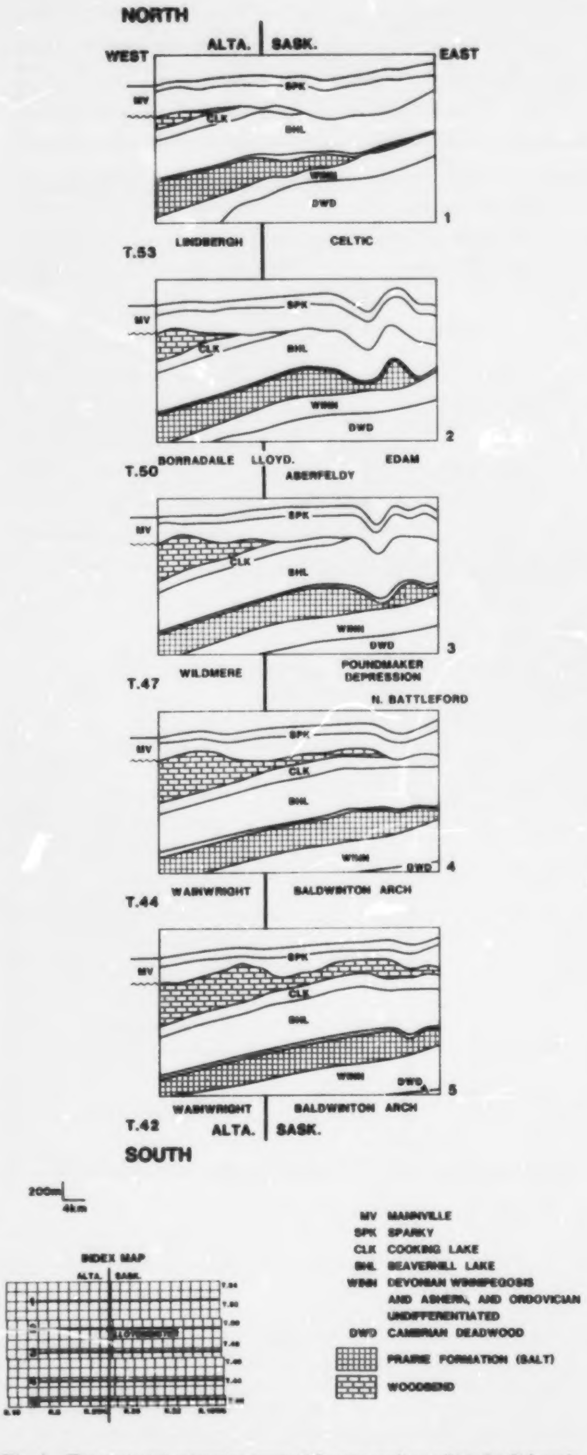

NORTH
WEST
EAST
ALTA.
SASK.
MV
SPK
CLK
BHL
WINN
DWD
1
T.53
LINDBERGH
CELTIC
2
T.50
BORRADAILE
LLOYD.
ABERFELDY
EDAM
3
T.47
WILDMERE
POUNDMAKER DEPRESSION
N. BATTLEFORD
4
T.44
WAINWRIGHT
BALDWINTON ARCH
5
T.42
WAINWRIGHT
BALDWINTON ARCH
ALTA.
SASK.
SOUTH
200m
4km
INDEX MAP
ALTA.
SASK.
MV MANNVILLE
SPK SPARKY
CLK COOKING LAKE
BHL BEAVERHILL LAKE
WINN DEVONIAN WINNIPEGOSIS AND ASHERN, AND ORDOVICIAN UNDIFFERENTIATED
DWD CAMBRIAN DEADWOOD
PRAIRIE FORMATION (SALT)
WOODBEND

Fig. 4 - Five west-east computer generated cross-sections relate the Paleozoic structure to the overlying Mannville Group. The cross-sections illustrate the Paleozoic ridges formed by the subcropping Devonian Woodbend Formation in the western part of the study area and the salt dissolution of the Prairie Formation in the eastern part. All deep Paleozoic tests in the area were used and originated partly from Digitech and partly from Husky Oil data. The Mannville tops are the author's own data and have also been used in Figures 7 and 8.

(Fig. 7) depicts a low corresponding to the area of salt dissolution. Thickening of the Base of Fish Scale Zone to pre-Cretaceous unconformity surface isopach map (Fig. 6) suggests that the area was structurally low during Cretaceous deposition.

Salt dissolution of the Prairie Formation in Saskatchewan has been documented to have occurred from the Devonian to the Recent (DeMille *et al.*, 1964; Holter, 1969; Horner and Hasegawa, 1978). Christopher (1980) indicated that some salt dissolution occurred during Mannville deposition but that most of the dissolution was post-Mannville. He, however, states that "solution sinks remained active throughout Mannville deposition and account for abrupt thickening and changing of facies in the latter". In the Edam area of Saskatchewan, Wilmot and Oliver (1983) have suggested that salt dissolution occurred in discrete phases that were interrrupted by periods of no salt dissolution. The oldest event was approximately synchronous with lower Mannville deposition (ibid). The major phase of dissolution occurred post-Second White Specks, and accounts for most of the structural highs and lows in the eastern part of the study area (ibid).

The Paleozoic carbonate ridges at the Pre-Cretaceous unconformity (Fig. 6) are dissected by paleo-valleys that connect the Lloyminster area with Central Alberta (Christopher, 1980). One paleo-valley is situated in the Manitou Lake area while another one occurs in the Vermilion area. These paleo-valleys are filled by lower Mannville (Dina) sandstones (Orr *et al.*, 1977; Vigrass, 1977; Christopher, 1980; Putnam, 1982). Sedimentation in the middle and upper Mannville has not been previously shown to be related to the pre-Cretaceous unconformity surface. This paper suggests that the paleotopography during Sparky deposition was similar to the pre-Cretaceous topography because the pre-Cretaceous ridges, and major low to the east, are also indicated on the second order residual map of the Sparky formation (Fig. 8). The magnitude of these highs and lows is, however, less than the pre-Cretaceous unconformity surface, suggesting lower topographic relief. Other evidence is presented later in this paper to support this relationship.

FACIES

INTRODUCTION

The Sparky formation can be subdivided into two major facies based on geophysical well log signatures and substantiated by cores. These facies are termed; a) Regional Facies and b) Channel Facies (van Hulten and Smith, in press). Generally, the formation is characterized by coarsening upward, sheet-like sandstones interbedded with siltstone/shale (Fig. 9). The lower boundary of the formation is the base of a regional shale, and a regional coal, the Sparky coal, generally caps the Sparky formation. This sequence is defined as the Regional Facies. In some areas, the Regional Facies and parts of the underlying formations have been eroded by Channel Facies which are sandstone and/or shale-filled channels (Figs. 11 and 12).

In the Lloydminster area, cores are not abundant and are generally confined to the edges of the older fields, enhanced oil recovery (EOR) projects, and newly discovered pools. Most of these cores are from the Regional Facies because of the more productive nature of this facies. Very few wells in the Channel Facies have been cored.

(a) Mineralogy

Mineralogical studies of the Sparky formation, in particular Maccagno and Watson (1980), Putnam (1982), and Smith (in

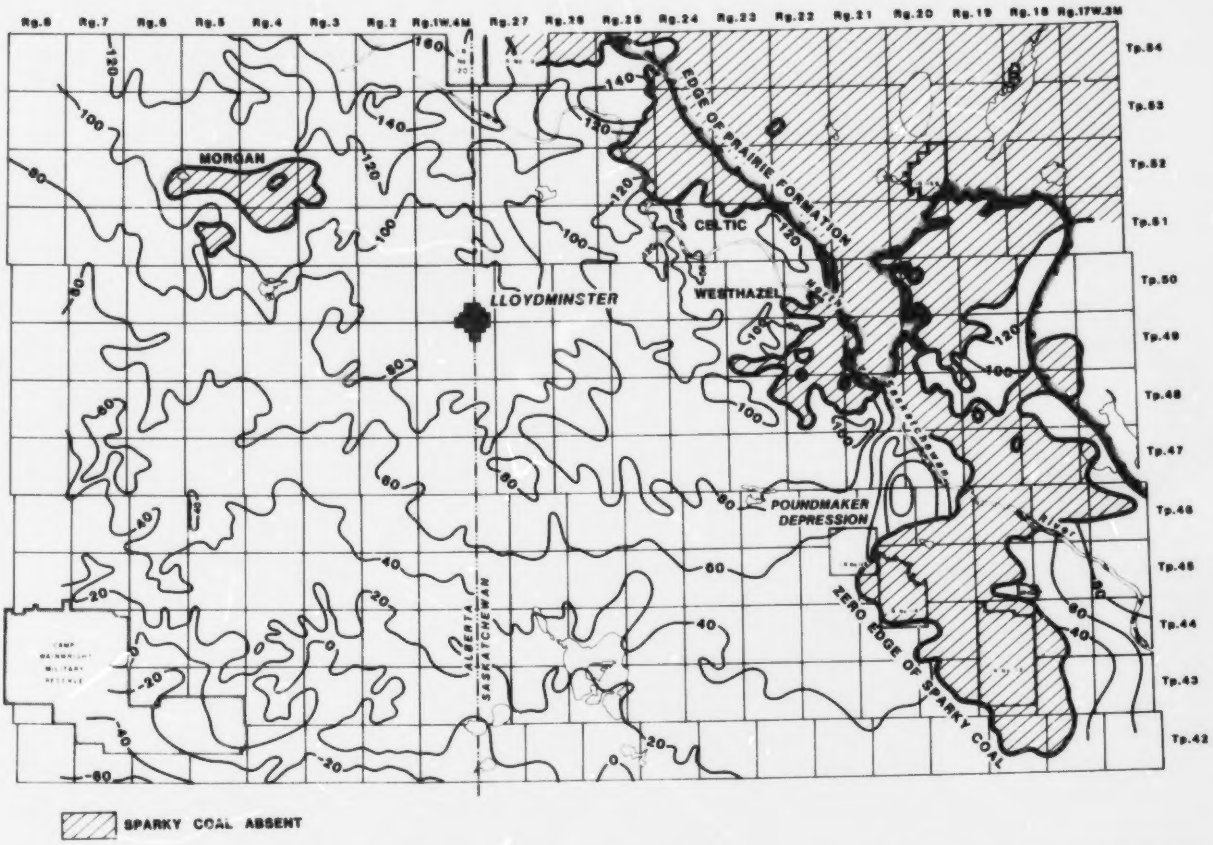


Fig. 5 - Sparky coal structure map illustrating the regional dip to the southwest, and the absence of the Sparky coal in the northeast and east. The edge of the Devonian Prairie Formation salt roughly coincides with the area where the Sparky coal is not present. (Map was constructed by using one well per section, if available.)

press) have shown that in the sandstone, siltstone, and also the shale beds, monocrystalline quartz is the principal framework grain (up to 90%) with polycrystalline quartz (up to 10%) occurring in lesser amounts. Feldspar (less than 10%), rock fragments (less than 5%) and other minerals (trace) such as glauconite, mica, and heavy minerals are minor constituents. The rock fragments are mainly shale, siltstone, and sandstone clasts. Plant remains and carbonaceous debris are common, particularly in the shale beds. Clays (up to 15%), and also carbonaceous material, form the depositional matrix between the framework grains. In the best reservoir sandstones, the clay content is typically between 2 and 6%.

The dominant clay mineral is kaolinite with illite being the next most abundant. Minor amounts of chlorite, smectite, and mixed-layer clays are present. Vermicular kaolinite booklets (60-90% of the clay fraction) occur as pore-filling cement. Illite (up to 40% of the clay fraction) and minor amounts of chlorite form the depositional matrix.

The shale beds have a slightly higher total clay content (11-12%, bulk XRD) compared to the sandstone and siltstone beds (2-6%). In the clay fraction (XRD), shales have a higher illite content (15-40%) than the sandstone/siltstone (10-18%), reflecting its increased detrital matrix.

Carbonates (siderite, dolomite, and calcite), kaolinite, and quartz overgrowths occur as pore-fill and pore-lining cements which reduce primary intergranular porosity. In rare cases, carbonate cementation has completely occluded all pore spaces.

(b) Log Response

The Gamma Ray curve should be used in preference to the Spontanteous Potential curve as a lithological indicator in the Sparky formation. The Gamma Ray counts are predominatly derived from illite and K-feldspar which are more abundant in the finer grained sediments, siltstone and shale, (Maccagno and Watson, 1980).

The Spontaneous Potential curve is influenced by formation fluids and permeability. Heavy oil and carbonate tight streaks can produce a positive Spontaneous Potential deflection, suggesting the lithology is a sandy siltstone or shale when, in fact, it is a clean sandstone. (Fig. 12 - see A11-26-47-22W3M, depth 454m, inidcated by number 1). Conversely, a waterleg may indicate a clean sandstone on the Spontaneous Potential log when the lithology is a shaly sandstone or siltstone (Fig. 9 - see 10A-32-49-1W4M, depth 605m, indicated by number 2). In the 10A-32-49-1W4 core, the Sparky D sub-unit is a siltstone whereas the Spontaneous Potential suggest it to be a clean sandstone.

The recognition between the Regional and Channel Facies is sometimes hampered by the Gamma Ray and Spontaneous

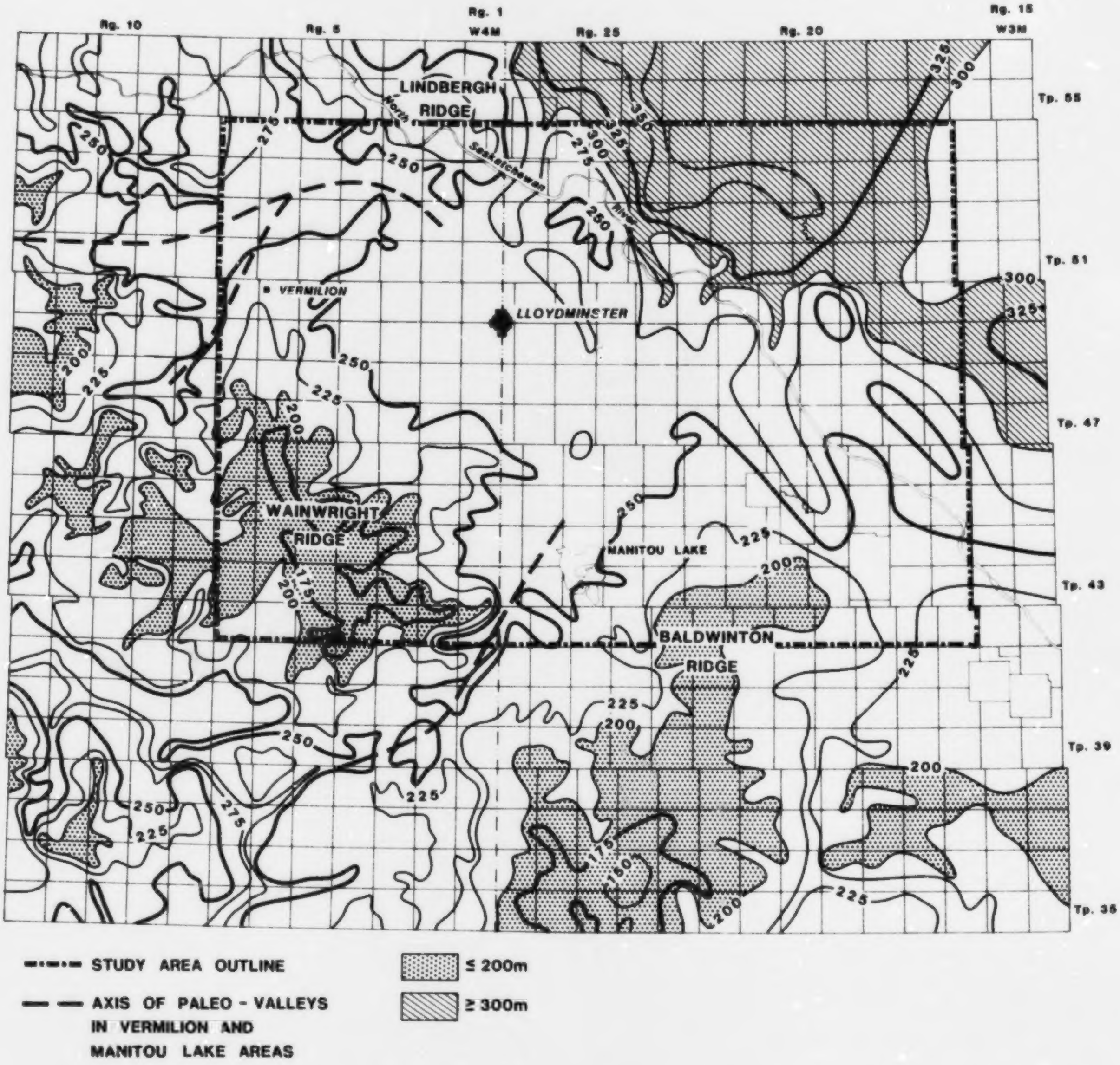

Rg. 10
Rg. 5
Rg. 1
W4M
Rg. 25
Rg. 20
Rg. 15
W3M
Tp. 55
Tp. 51
Tp. 47
Tp. 43
Tp. 39
Tp. 35
LINDBERGH RIDGE
North Saskatchewan River
VERMILION
LLOYDMINSTER
WAINWRIGHT RIDGE
MANITOU LAKE
BALDWINTON RIDGE
150
175
200
225
250
275
300
325
350
STUDY AREA OUTLINE
AXIS OF PALEO - VALLEYS IN VERMILION AND MANITOU LAKE AREAS
≤ 200m
≥ 300m

Fig. 6 - Isopach map of the Base of Fish Scale Zone to Pre-Cretaceous unconformity surface, using data derived by previous Husky Oil workers. One Paleozoic well per section was used if available. The map outlines the boundaries of the Lloydminster Sub-basin.

Potential curves having different log signatures. The Gamma Ray curve should be used in these cases to determine if the log signature is a coarsening upward sequence, typical of the Regional Facies, or a blocky or bell shaped curve, typical of the Channel Facies. For example, a water zone at the base of a Channel Facies sand may produce a negative Spontaneous Potential response whereas heavy oil suppression in the upper part gives a positive Spontaneous Potential response. The Spontaneous Potential curve may show in some cases a blocky or bell-shaped curve suggesting a channel-fill whereas the Gamma Ray curve will display a typical coarsening upward sequence indicating Regional Facies' log character.

REGIONAL FACIES

(a) Descripton

The Regional Facies is defined as the stratigraphic sequence between the Sparky coal, or its stratigraphic equivalent (ie. the overlying Waseca beds are correlatable), and the basal Sparky shale (Fig. 9). The sequence varies from 10-20m in thickness. The basal Sparky is a carbonaceous, bioturbated, silty shale, generally 1-3m thick. This sub-unit is correlatable over the entire study area except where it has been removed by erosion. Dinoflagellates and foraminifera have been identified in the

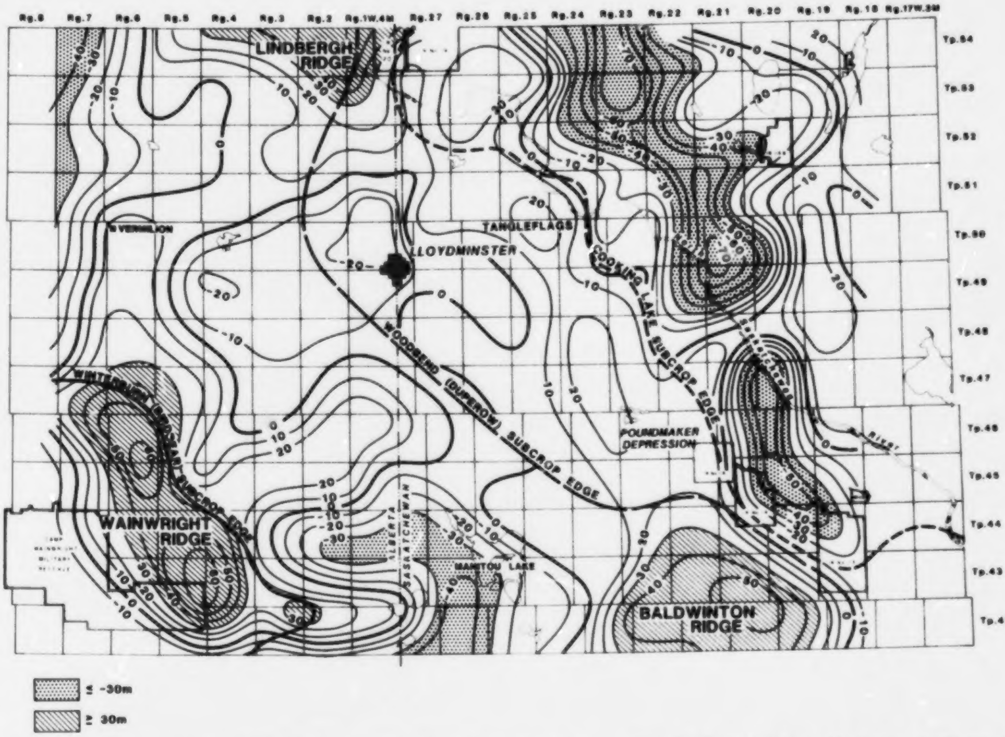
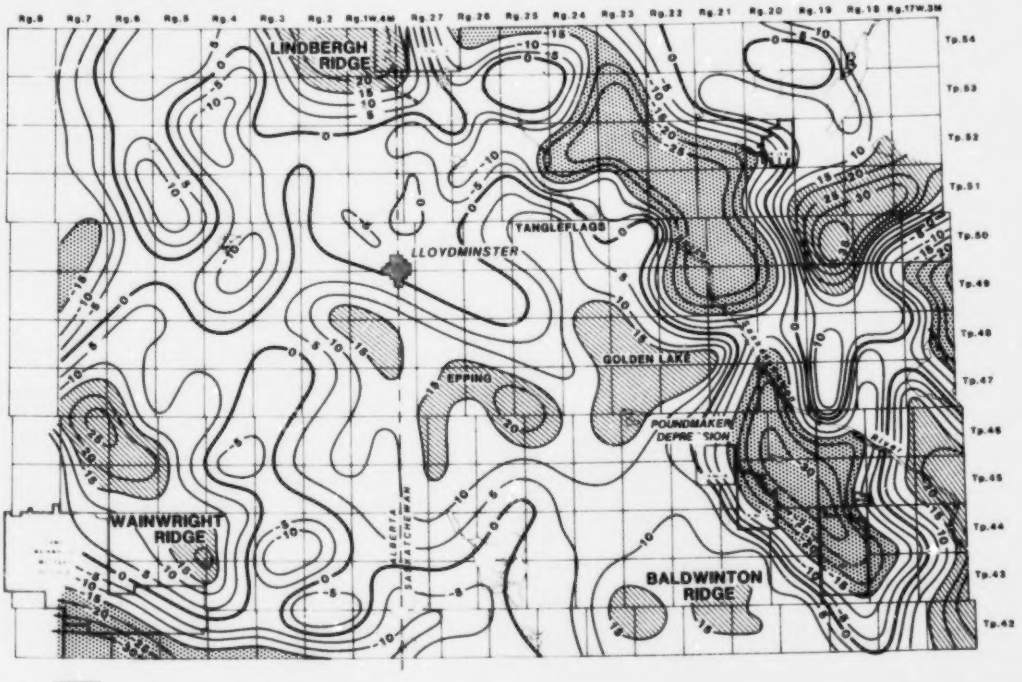

LINDBERGH RIDGE
VERMILION
TANGLEFLAGS
LLOYDMINSTER
COOKING LAKE SUBCROP EDGE
WOODBEND (DUPEROW) SUBCROP EDGE
WINTERBURN (NISKU) SUBCROP EDGE
POUNDMAKER DEPRESSION
WAINWRIGHT RIDGE
MANITOU LAKE
BALDWINTON RIDGE
ALBERTA
SASKATCHEWAN
Tp.54
Tp.42
≤ -30m
≥ 30m

Fig. 7 - Second order residual map of the Pre-Cretaceous unconformity surface illustrating the major structural elements of the Lloydminster Sub-Basin. (Map was generated by using one data point per township. First, second, and higher order residual maps depict the same features. The second order residual map provided optimal definition of the ridges bordering the sub-basin.)

Fig. 8 - Second order residual map on the top of the Sparky formation illustrating the features which were also observed on the second order residual map of the Pre-Cretaceous unconformity surface. The magnitude of these high and low areas is, however, less. (Map was generated using one data point per township.)


LINDBERGH RIDGE
TANGLEFLAGS
LLOYDMINSTER
GOLDEN LAKE
EPPING
POUNDMAKER DEPRESSION
WAINWRIGHT RIDGE
BALDWINTON RIDGE
ALBERTA
SASKATCHEWAN
Tp.54
Tp.42
≤ - 15m
≥ 15m

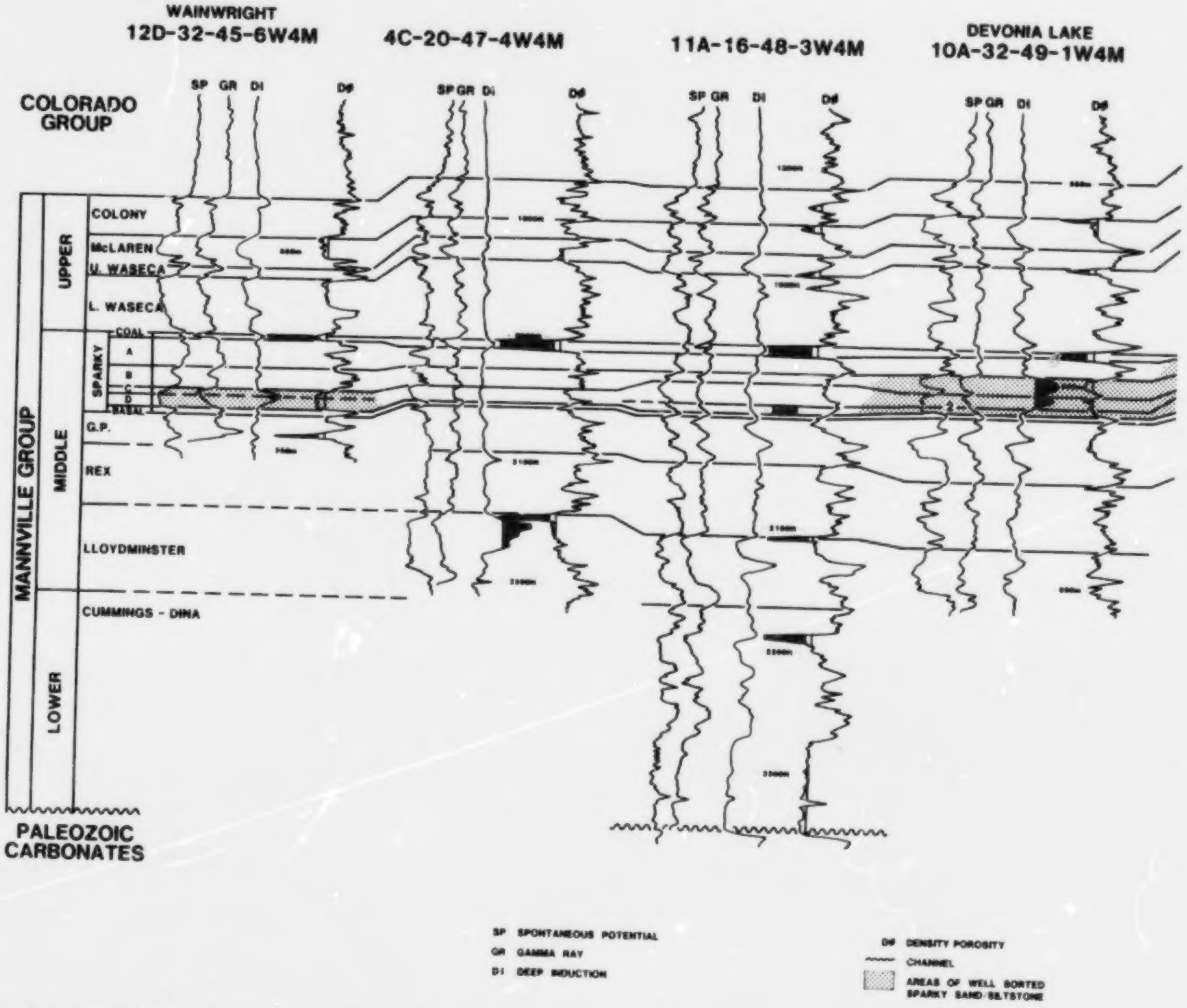
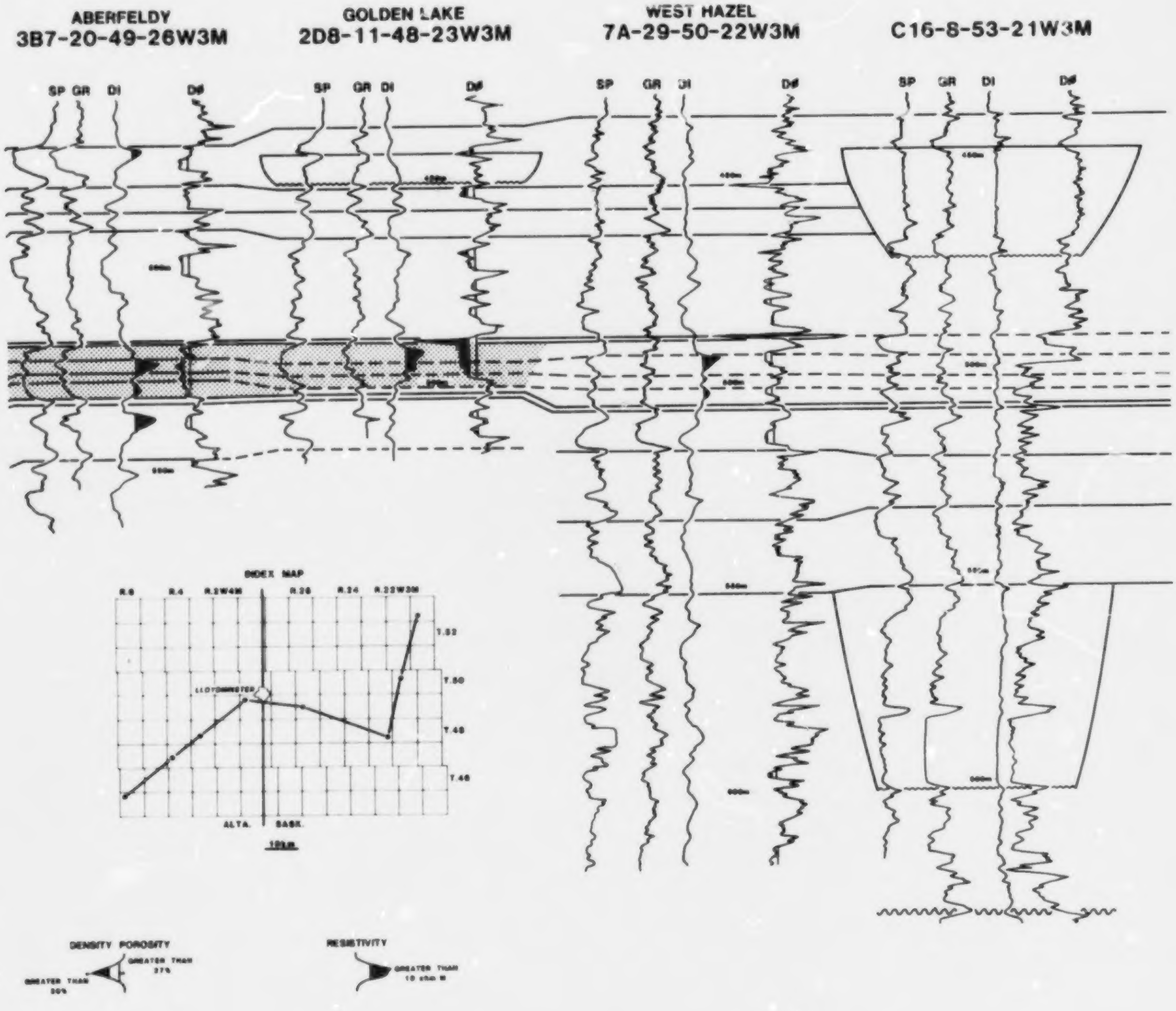

WAINWRIGHT
12D-32-45-6W4M
4C-20-47-4W4M
11A-16-48-3W4M
DEVONIA LAKE
10A-32-49-1W4M
SP GR DI DΦ
COLORADO GROUP
COLONY
McLAREN
U. WASECA
L. WASECA
COAL
A
B
C
D
BASAL
SPARKY
G.P.
REX
LLOYDMINSTER
CUMMINGS - DINA
UPPER
MIDDLE
LOWER
MANNVILLE GROUP
PALEOZOIC CARBONATES
SP SPONTANEOUS POTENTIAL
GR GAMMA RAY
DI DEEP INDUCTION
DΦ DENSITY POROSITY
CHANNEL
AREAS OF WELL SORTED SPARKY SAND-SILTSTONE

Fig. 9 - Regional southwest-northeast stratigraphic cross-section of the Mannville Group in the Lloydminster area, illustrating the correlation of the Sparky formation, its sub-units, and the development up-section of the sandstone/siltstone sub-units to the northeast. (Datum: top of Sparky coal; dashed lines indicate areas of uncertain correlation.)

basal Sparky at Aberfeldy by Fuglem (1970) and AGAT Consultants Ltd. (pers. comm.).

Subdivision of the Sparky formation into sub-units between the Sparky coal and basal Sparky has been useful in mapping in particular pools and fields (MacCallum, 1979; Maccagno and Watson, 1980; Smith, in press). On the Alberta and part of the Saskatchewan side of the study area, these sub-units are correlatable (Fig. 9). Although correlations can be made, they are more uncertain in eastern parts of the study area. These subdivisions are informally termed, in descending order A, B, C, D. The base of the A, B, C and D sub-units is indicated on the Gamma Ray and/or Spontaneous Potential logs as a shale bed. In cores, the basal bed can vary from a silty sandstone to interbedded shale/sandstone to shale. Regionally, the Sparky coal, A sub-unit and basal Sparky appear to be the most continous sub-units with the major facies changes occurring in the B, C and D intervals.

Each of these sub-units generally represents a coarsening upward sequence, varying from 2 to 6m thick. Either silty sandstone, interbedded shale/sandstone or shale occurs at the base and grades upwards into coarser grained and better sorted sandstone or siltstone. The lower part of the coarsening upward sequence can be either bioturbated or wavy-bedded. Wave ripples and plant debris along laminae are frequently observed. Vertical corkscrew type burrow, *Gyrolythos* (G. Pemberton, pers. comm.) are common, particularly in the lower sub-units, C and D. The sandstone interbeds are very fine grained and moderately well sorted. The sandstones at the top of the coarsening upward sequence are dominantly very fine to fine grained and well sorted. In some pools, the reservoir is not always a sandstone but is actually a well sorted, quartzose siltstone; for example the lower two-thirds of the reservoir in the Wainwright Field and the lower sub-units in the Aberfeldy Field. Sedimentary structures in the sandstone beds are often difficult to observe due to the heavy oil staining. Low angle and parallel laminations are the dominant sedimentary structures observed. Bioturbation and wave ripples are



more common in sub-unit C and more particularly sub-unit D. High angle laminations (tabular cross-beds?) have been observed, usually in sub-unit B or in sub-units exhibiting a blocky log character.

(b) Lateral Lithological Variations

Laterally, the upper sandstone/siltstone portion of the sub-units can grade into shale or interbedded sandstone/shale. This aspect is illustrated in the regional southwest-northeast cross-section between the Wainwright, Devonia Lake, Aberfeldy and Golden Lake Fields (Fig. 9) (van Hulten and Smith, in press).

The A sub-unit at Wainwright and Devonia Lake, is composed predominatly of carbonaceous, silty shale with minor carbonate cemented sandstone. At Aberfeldy and Golden Lake, however, this sub-unit is a moderately to well sorted, very fine to fine grained, quartzose sandstone. In addition, the sub-unit at Devonia Lake, Aberfeldy, and Golden Lake is also a well sorted, very fine to fine grained, quartzose sandstone, whereas at Wainwright, it is a carbonaceous, silty shale with a thin, carbonate cemented sandstone occurring at the top of the sequence. The development of the sandstone sub-units up-section towards the northeast is interpreted as to representing progradation in the same direction (Fig. 9).

The major sandstone body trends correspond to the areas of net pay development in the Regional Facies. In the Wainwright Fields, the sandstone/siltstone body is thin and occurs in the C and D sub-units. The Blackfoot/Epping/Aberfeldy/Golden Lake area is characterized by thick development of sandstone/siltstone in the B to D sub-units. The net pay is thickened in the Aberfeldy/Golden Lake area by the addition of porous sandstones in the A sub-unit. In general, the B sandstone sub-unit is best developed in the Blackfoot/Aberfeldy/Epping Golden Lake area (Fig. 9).

Sparky sub-units are generally correlatable within pools and also regionally between some of the pools. A detailed study of

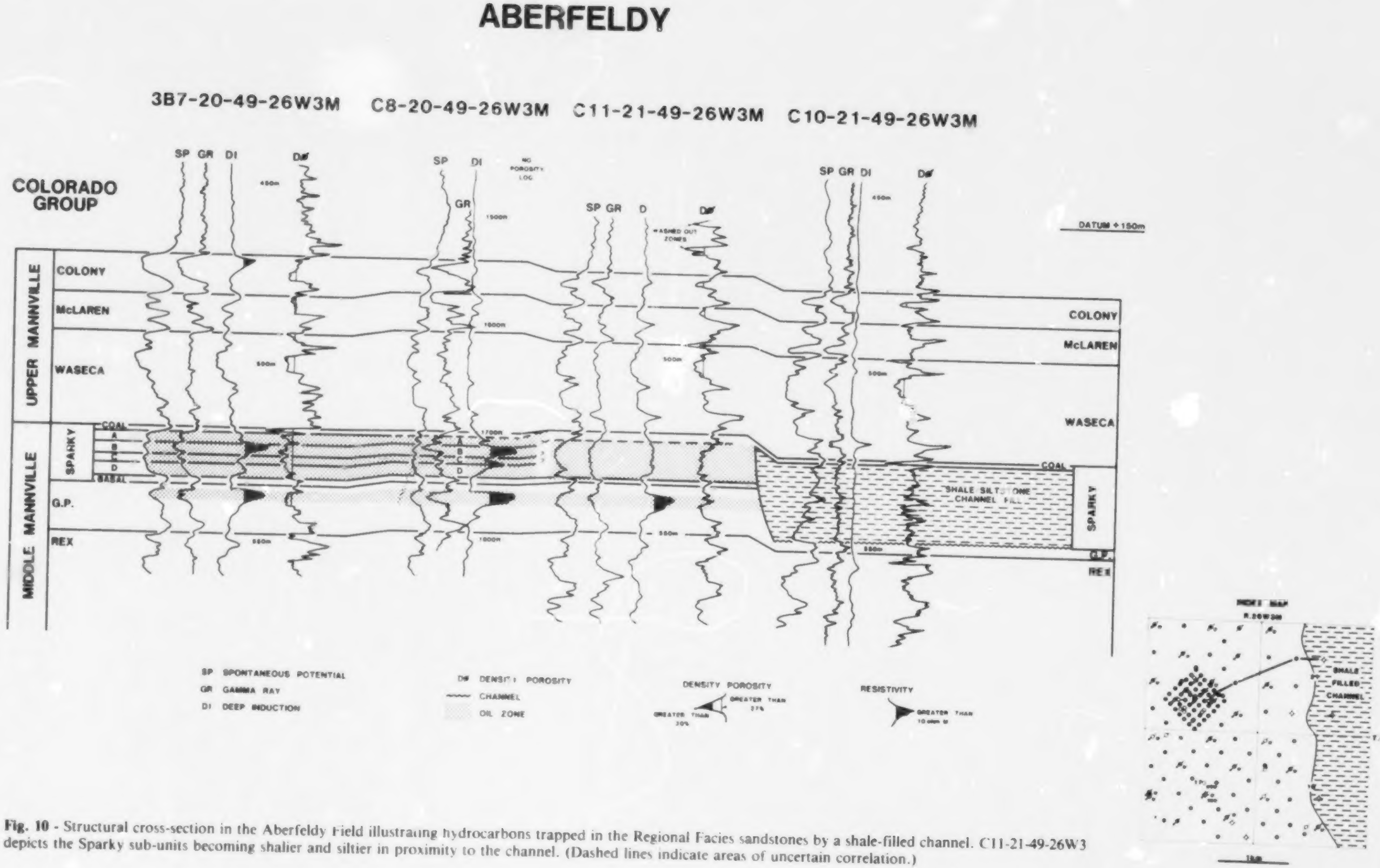

ABERFELDY
3B7-20-49-26W3M
C8-20-49-26W3M
C11-21-49-26W3M
C10-21-49-26W3M
COLORADO GROUP
UPPER MANNVILLE
MIDDLE MANNVILLE
COLONY
McLAREN
WASECA
SPARKY
COAL
A
B
C
D
BASAL
G.P.
REX
SP
GR
DI
Dϕ
D
NO POROSITY LOG
WASHED OUT ZONES
450m
500m
550m
1500m
1600m
1700m
1800m
DATUM + 150m
SHALE SILTSTONE CHANNEL FILL
SP SPONTANEOUS POTENTIAL
GR GAMMA RAY
DI DEEP INDUCTION
Dϕ DENSITY POROSITY
CHANNEL
OIL ZONE
DENSITY POROSITY
GREATER THAN 27%
GREATER THAN 30%
RESISTIVITY
GREATER THAN 10 ohm m
INDEX MAP
R.26W3M
SHALE FILLED CHANNEL
T.49
1km

Fig. 10 - Structural cross-section in the Aberfeldy Field illustrating hydrocarbons trapped in the Regional Facies sandstones by a shale-filled channel. C11-21-49-26W3 depicts the Sparky sub-units becoming shalier and siltier in proximity to the channel. (Dashed lines indicate areas of uncertain correlation.)

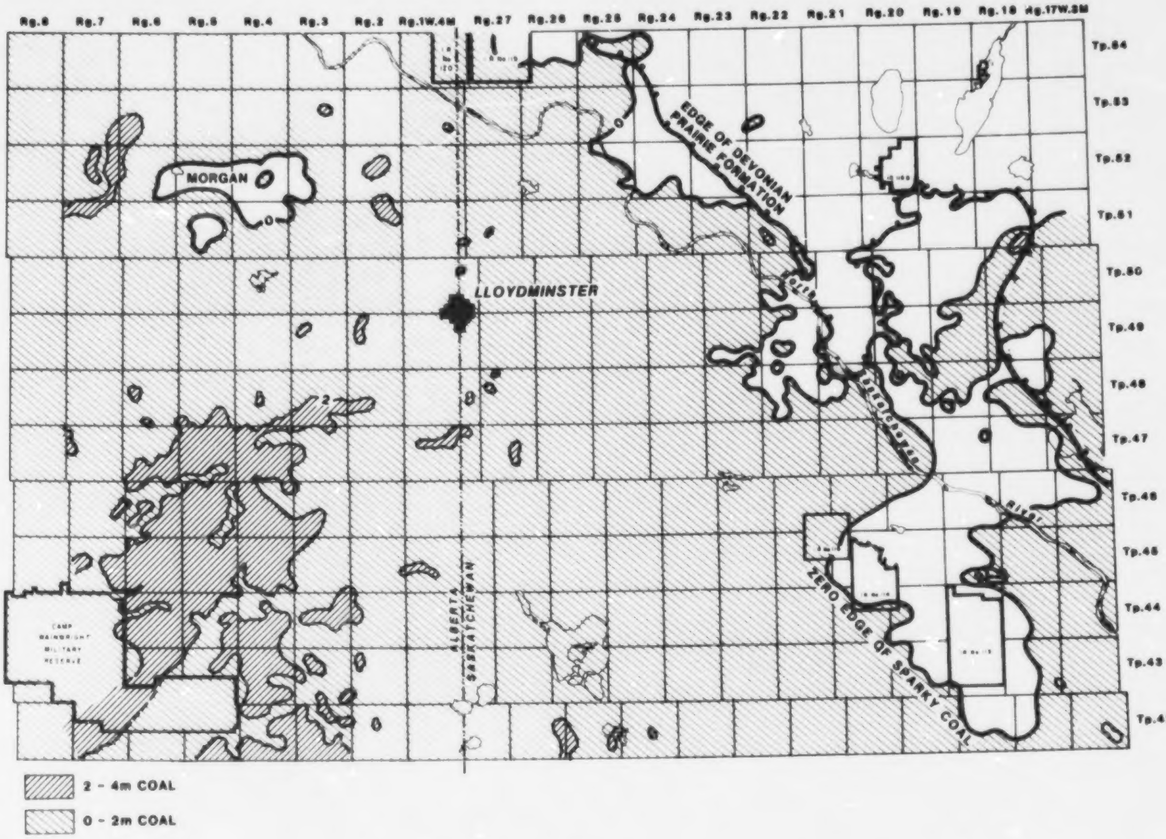

Rg.8
Rg.7
Rg.6
Rg.5
Rg.4
Rg.3
Rg.2
Rg.1W.4M
Rg.27
Rg.26
Rg.25
Rg.24
Rg.23
Rg.22
Rg.21
Rg.20
Rg.19
Rg.18
Rg.17W.3M
Tp.54
Tp.53
Tp.52
Tp.51
Tp.50
Tp.49
Tp.48
Tp.47
Tp.46
Tp.45
Tp.44
Tp.43
Tp.42
MORGAN
LLOYDMINSTER
EDGE OF DEVONIAN PRAIRIE FORMATION
ZERO EDGE OF SPARKY COAL
ALBERTA SASKATCHEWAN
RIVER
CAMP WAINWRIGHT MILITARY RESERVE
2 - 4m COAL
0 - 2m COAL

Fig. 11 - Sparky coal isopach map indicating the thick coal development in the Wainwright area and the absence of the Sparky coal to the northeast and east, roughly coinciding with the edge of the Devonian Prairie Formation salt.

the Aberfeldy steamflood pilot, (Smith, in press), however, illustrates that correlation of these sub-units becomes difficult when either:

(a) the lower shale beds in the coarsening upward sequence were not deposited such that the sandstones of the sub-unit directly overlie the underlying sub-unit's sandstone body; or

(b) a sandstone body pinches out laterally so the lower shale beds were deposited on top of the underlying sub-unit's lower shale beds.

Differentation within part or all of the Sparky formation into these sub-units is impossible when the log signature has a general blocky character, representing continuous silty sandstone or clean sandstone. This commonly occurs in areas adjacent to the Channel Facies (Fig. 10). Channel - like features on well logs (blocky or bell shaped log signature) are recognized within the B to basal Sparky interval(e.g. Marsden South Pool). The basal Sparky is still present so it falls within the definition of the Regional Facies. The Gamma Ray log signature, absence of correlatable sub-units (C and D) and presence of tabular cross-beds suggests these deposits may be channel-fill sandstones.

(c) Sparky Coal

The Sparky coal is a sub-bituminous coal bed (AGAT, pers. comm.) with interbeds of carbonaceous shale, and an associated underlying carbonaceous shale with rootlets. This sub-unit is up to 6m thick but is generally between 1 and 3m thick. Interbedded silty sandstone, siltstone and shale can locally underlie this sequence.

The Sparky coal is present throughout most the study area (Fig. 11). A northeast trending isopach thick occurs in the Wainwright area. The zero edge of the Sparky coal is located in the eastern part of the study area and also locally in the Morgan area of Alberta (ibid). Locally, the Sparky coal may not be present while adjacent wells have the coal developed (Fig. 10). The absence of the coal in isolated wells is interpreted to be due to non-deposition and not caused by post-Sparky channeling because the sub-units and the overlying Waseca formation sequence are correlatable from well to well.

CHANNEL FACIES

(a) Definition

The Channel Facies is recognized by the absence of the basal Sparky marker bed which is facilitated by the absence of the underlying General Petroleums and Rex formations. Upper Mannville channeling has occurred throughout the Lloydminster area (Fig. 12) but the Channel Facies referred to in this study are channel-fill deposits originating during Sparky deposition shown by the presence of the Sparky coal.

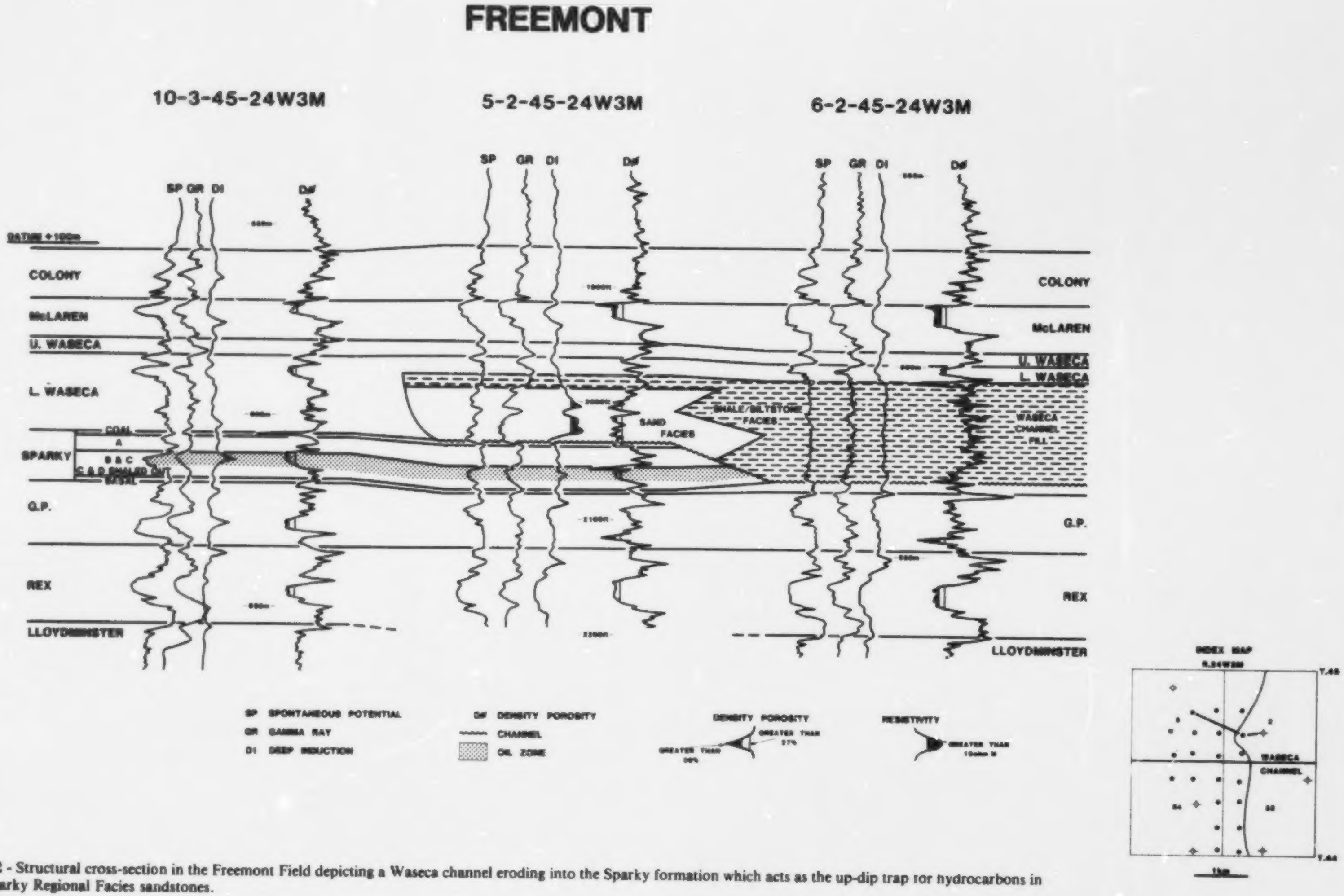

FREEMONT
10-3-45-24W3M
5-2-45-24W3M
6-2-45-24W3M
SP GR DI
Dø
DATUM +100m
COLONY
McLAREN
U. WASECA
L. WASECA
COAL
A
SPARKY
B & C
C & D SHALED OUT
BASAL
G.P.
REX
LLOYDMINSTER
SAND FACIES
SHALE/SILTSTONE FACIES
WASECA CHANNEL FILL
1900m
2000m
2100m
2200m
SP SPONTANEOUS POTENTIAL
GR GAMMA RAY
DI DEEP INDUCTION
Dø DENSITY POROSITY
CHANNEL
OIL ZONE
DENSITY POROSITY
GREATER THAN 27%
GREATER THAN 30%
RESISTIVITY
GREATER THAN 10ohm m
INDEX MAP
R.24W3M
T.45
T.44
WASECA CHANNEL
2
34
35
1km

Fig. 12 - Structural cross-section in the Freemont Field depicting a Waseca channel eroding into the Sparky formation which acts as the up-dip trap for hydrocarbons in the Sparky Regional Facies sandstones.

Three major well log signatures (Gamma Ray and Spontaneous Potential) are identifiable for the Channel Facies:

(a) uniform, deflection to the right (positive Spontaneous Potential; high Gamma Ray) - indicative of shale/siltstone-filled channel (Fig. 10),

(b) bell shaped curve - indicative of a fining upwards sequence from sandstone to shale/siltstone (Fig. 13),

(c) blocky curve - indicative of a sandstone-filled channel (Fig. 13).

(b) **Correlation Problems**

Whether or not the Channel Facies is a Sparky, or pre-Sparky channel-fill deposit is sometimes difficult to determine. The basal Sparky marker is, however, distinctive and regionally correlatable so if the Channel Facies was associated with deposition of the pre-Sparky deposits, the basal Sparky would be present. Cores are rare within the Channel Facies, but when they are available, the basal Sparky marker is not observed.

Thin sandstone beds at the top of the sequence can be correlated as the A, B, C and/or D sub-units (Fig. 13) or may be part of the Channel Facies. These sandstone beds may be interpreted as sandstones of the Sparky sub-units which have migrated over an abandoned channel or as late sandstone deposits associated with the abandonment phase of the channel.

(c) **Description**

The Channel Facies varies from shale-filled to sandstone-filled; however, the most dominant type is the shale-filled channel. Sandstone-filled channels are developed locally and the major occurrences are illustrated in Figure 14. The better developed channel-fill sandstones are well sorted and slightly coarser grained (fine to medium grained) than the Regional Facies sandstones.

The Channel Facies are generally 10-30m thick, and locally up to 50 m thick; they vary from 0.3 to 2 km wide and may extend to tens of kilometres, but do not exceed 100 km in length. The sandstone Channel Facies appear to form wedge-shaped sandstone bodies such as that present in Home Oil's Kitscoty EOR project. Many of these channel deposits have not, however, been delineated by drilling so the sand body geometry has to be inferred from seismic.

(d) **Distribution**

Channel migraton and abandonment make it difficult to determine the initial trend of many of the Sparky channels. The general trend appears to be northwest-southeast.

Distribution of the Channel Facies is not uniform across the study area. The authors have outlined three areas of channeling (Fig. 14):

(a) Wainwright,
(b) Blackfoot/Aberfeldy/Epping,
(c) Golden Lake/Celtic Edam.

Channeling around the Wainwright area does not appear to connect with the other two areas but this may be explained by the lack of well control. The Blackfoot/Aberfeldy/Epping area appears to be connected with the Golden Lake/Celtic/Edam area; however, the Golden Lake/Celtic/Edam area has thicker channel-fill sandstone deposits.

ENVIRONMENTAL DISCUSSION

(a) **Effect of Pre-Cretaceous Paleo topography on Sparky Deposition**

The Pre-Cretaceous topography as derived from the Base of Fish Scale Zone to Pre-Cretaceous unconformity surface isopach map (Fig. 6) is also reflected on the second order residual maps of the Pre-Cretaceous unconformity surface (Fig. 7) and the Sparky formation (Fig. 8). All the maps depict the Pre-Cretaceous ridges and the paleo-low to the east.

The absence of the Sparky coal to the east roughly corresponds to the paleo-low indicated on the Base of Fish Scale Zone to Pre-Cretaceous unconformity surface isopach map (Fig. 6) suggesting the paleo-low was present during Sparky deposition. The widespread distribution of the Sparky coal indicates a low relief topography.

The thickest development of sandstone/siltstone of the Regional Facies (Fig. 2) and more abundant channeling occur between the Lindbergh and Baldwinton Ridges in the center of the Lloydminster Sub-Basin. In the Wainwright area, sandstone/siltstone occur in the Wainwright Ridge which was probably a topographic high relief feature during the early stages of Sparky deposition. However, the thickening of the Sparky coal in the Wainwright area, between the Manitou Lake and Vermilion paleo-valleys (Fig. 6), suggests that this area represents marsh deposition within a slowly subsiding lagoon or interdistributary bay during the final stages of Sparky deposition.

(b) **Timing of the Channel Facies**

Channeling occurred prior to Sparky coal deposition as indicated by the Sparky coal overlying the channel-fill (Figs. 10 and 13). Some channeling may in fact be contemporaneous with deposition of the Regional Facies although difficult to prove. Contemporaneous deposition is suggested by:

(1) The Sparky sandstones occasionally become shalier and siltier in proximity to the Channel Facies (Fig. 10),

(2) Channel-fill sandstones are associated with areas in which Regional Facies sandstones such as the B sub-unit are better developed,

(3) Adjacent to the Channel Facies, the Sparky coal can split into two coal beds similar to levee deposits adjacent to channels described by Horne *et al.* (1978).

Channels have eroded down as deeply as the Lloydminster formation. Sparky sandstones, which may correlate as the A, B and/or C sub-units, overlie the Channel Facies (Fig. 13), but whether or not the sandstones are actually these sub-units or late sand influxes during channel abandonment cannot be determined. In these cases, the development of the Channel Facies may be as early as pre-C sub-unit to as late as post-A sub-unit deposition.

At the Aberfeldy steamflood pilot (Smith, in press), a narrow intra-Sparky channel-fill deposit, originated either during A sub-unit or pre-Sparky coal deposition. This interpretation was based on:

(a) The Sparky coal overlying the sequence,

(b) The A sub-unit is absent within this feature. The B, C and D sub-units generally underlie this area but locally the B and part of the C sub-units are also missing,

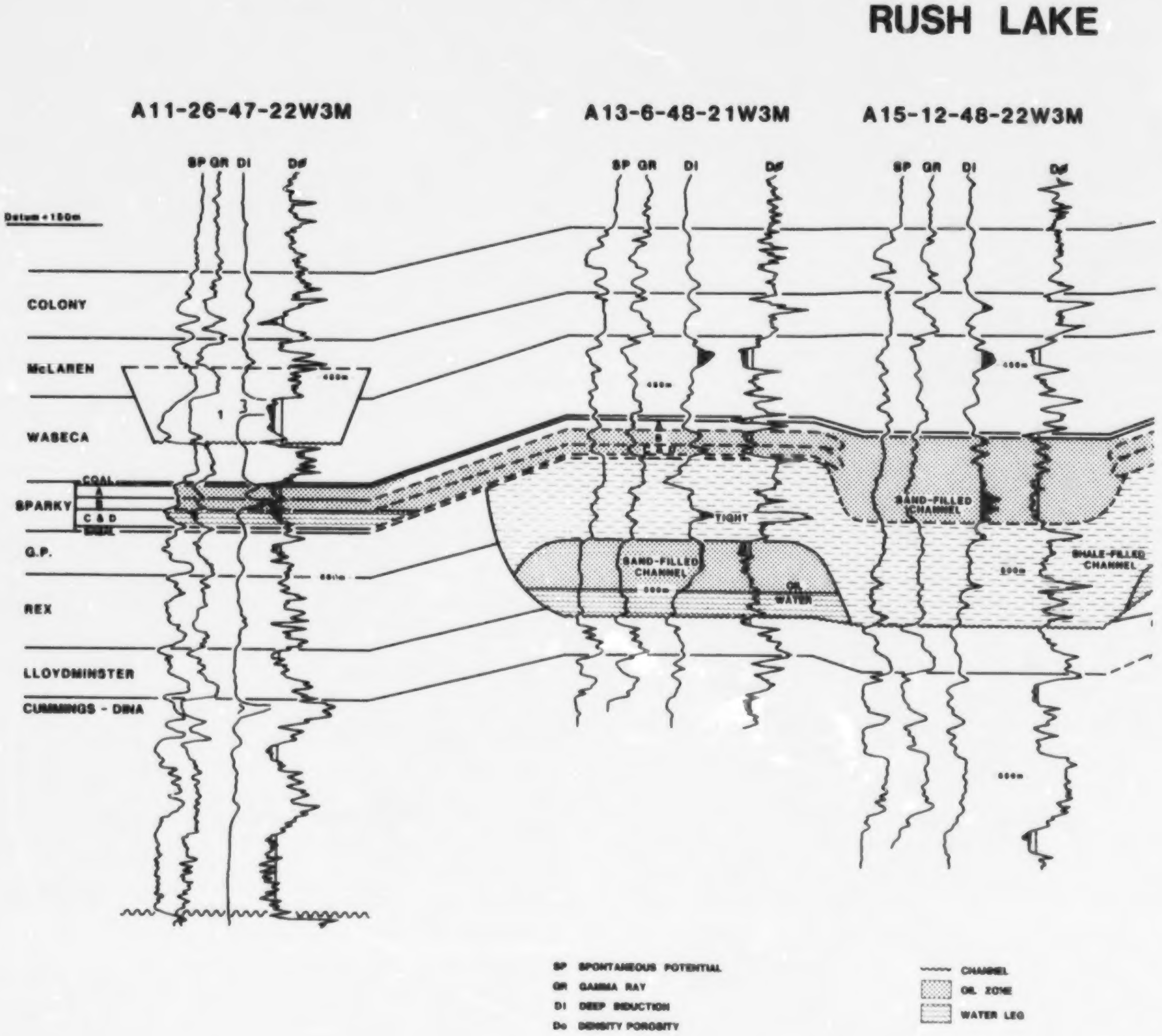

RUSH LAKE
A11-26-47-22W3M
A13-6-48-21W3M
A15-12-48-22W3M
SP GR DI Dø
Datum +150m
COLONY
McLAREN
WASECA
SPARKY
COAL
A
C & D
BASAL
G.P.
REX
LLOYDMINSTER
CUMMINGS - DINA
SAND-FILLED CHANNEL
TIGHT
OIL
WATER
SHALE-FILLED CHANNEL
SP SPONTANEOUS POTENTIAL
GR GAMMA RAY
DI DEEP INDUCTION
Dø DENSITY POROSITY
CHANNEL
OIL ZONE
WATER LEG

Fig. 13 - Structural cross-section in the Rush Lake Field showing hydrocarbons trapped within sandstone bodies of the Channel Facies. (Dashed lines indicate areas of uncertain correlation.)

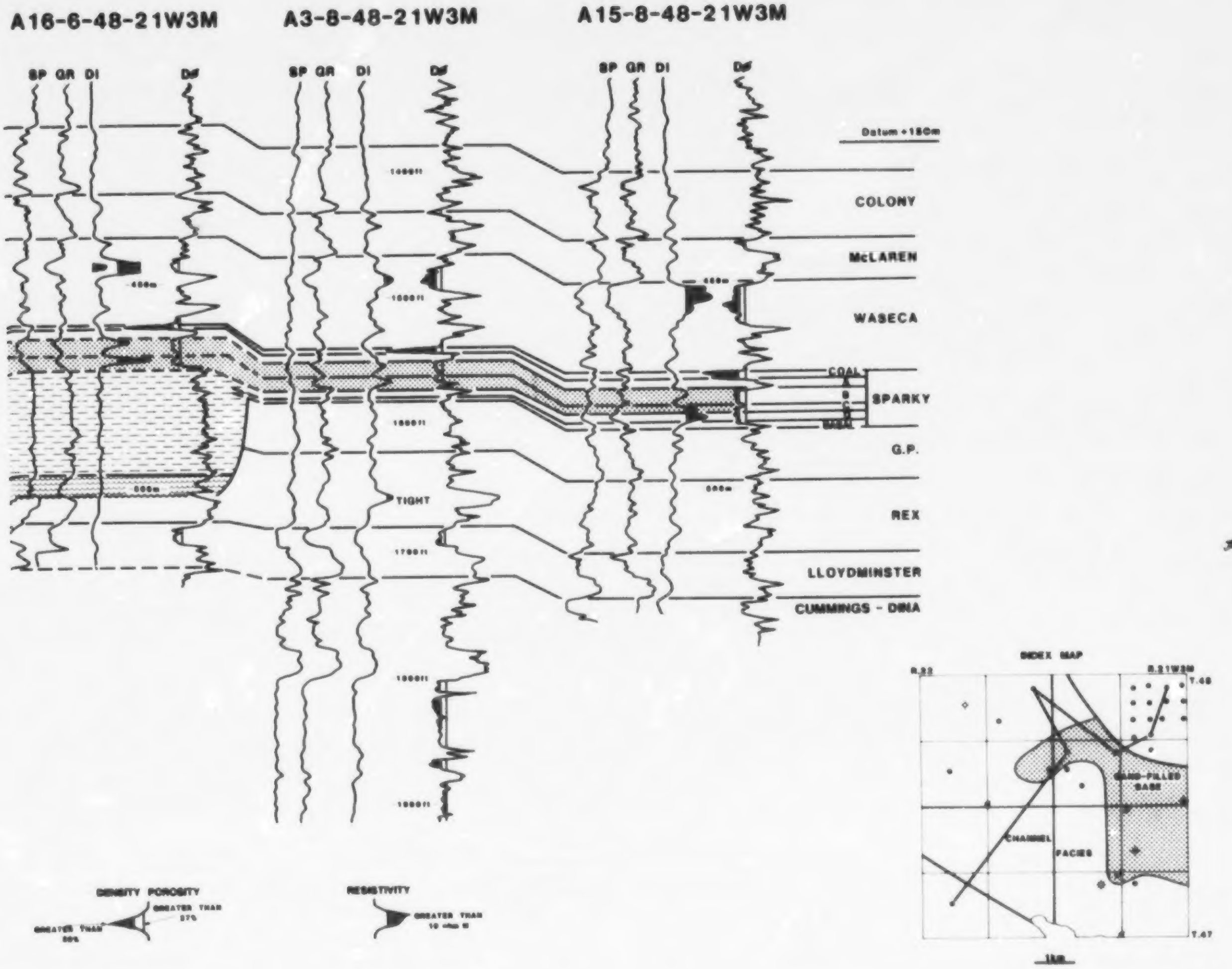
(c) the Sparky formation thins into this area with the change occurring over a very short distance, less than 100m.

This narrow channel-fill can be traced to the shale-filled Channel Facies bounding the eastern side of the Aberfeldy Field so the channel-fill was interpreted to represent a crevasse splay channel which was abandoned and filled with silty sandstones, siltstones, and shale.

(c) Environmental Interpretation of Regional and Channel Facies

In the Regional Facies, the presence of foraminifera (Fuglem, 1970), dinoflagellates (Fuglem, 1970; Putnam, 1982), glauconite, and the well sorted, quartzose nature of the sandstones indicate marine deposition. The coarsening upward sequence as indicated by the lithology and grain size, and the sedimentary structures (low angle and parallel laminations, wave ripples and bioturbation) are similar to sequences in a wave-dominated shoreline (Orr *et al.*, 1977; Putnam, 1982).

A detailed core and mapping study of the Aberfeldy steamflood pilot (Smith, in press) suggested that the Sparky formation was composed of four depositional units: basal Sparky, lower Sparky (B, C and D sub-units), upper Sparky (A sub-unit), and Sparky coal. The basal Sparky represents restricted marine deposits. The lower Sparky was interpreted as a cyclic series of shoreface sandstones with marine siltstones and shale which were then disconformably overlain by interdistributary bay shale and crevasse splay sandstones of the A sub-unit. The narrow channel-fill, which originated either during a sub-unit sandstone deposition or pre-Sparky coal deposition, was probably an abandoned crevasse channel. Marsh sediments, with an associated root zone, of the Sparky coal


A16-6-48-21W3M
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COLONY
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WASECA
COAL
SPARKY
BASAL
G.P.
REX
LLOYDMINSTER
CUMMINGS - DINA
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INDEX MAP
R.22
R.21W3M
T.48
T.47
SAND-FILLED BASE
CHANNEL
FACIES
1km
DENSITY POROSITY
GREATER THAN
RESISTIVITY

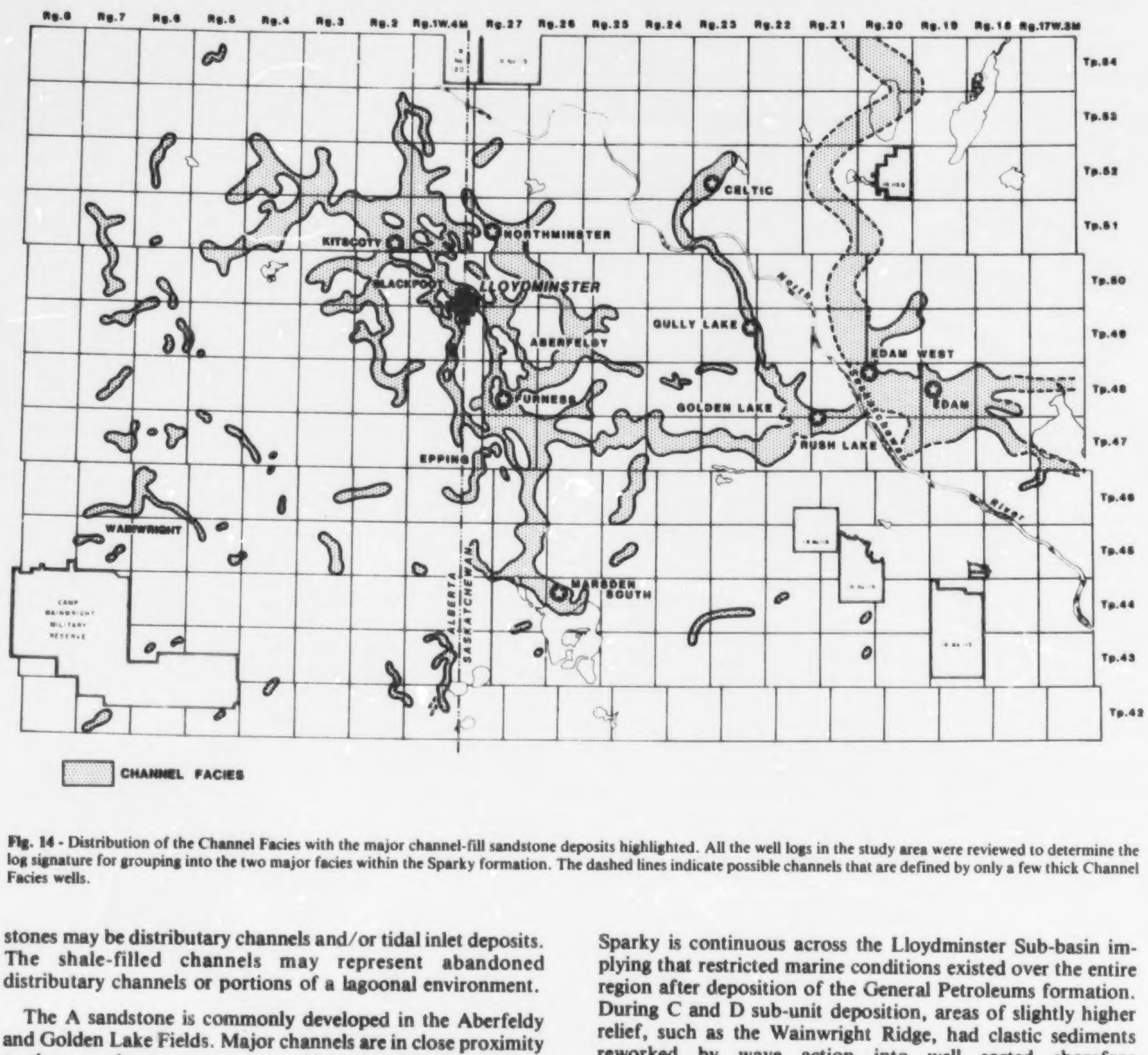
then were deposited over the entire sequence. Smith (in press) interpreted this sequence to represent part of a wave dominated delta.

In other parts of the study area, the characteristics of the Sparky formation also indicate a wave dominated deltaic sequence. That the basal Sparky was deposited in a restricted marine environment is indicated by the presence of dinoflagellates and foraminifera. In addition, the sedimentary structures and sediments themselves suggest a low energy environment.

Interbedded sandstone, siltstone, and shale of the C and D sub-units are interpreted as shoreface deposits from the presence of vertical burrows, wavy bedding, and wave ripples. In the Wainwright area, however, well sorted, cross-bedded (wave ripples) siltstones/sandstones indicate that these sub-units were deposited in higher energy environment.

In the B sub-unit, the sandstone is thicker and better sorted in the central protion of the Lloydminster Sub-basin. Here the B sandstone is interpreted to be an upper shoreface deposit due to its well sorted character and the occurrence of low angle and parallel laminations. Towards the southwest and northeast, the B sub-unit grades into shale and siltstone with occasional sandstone beds. These deposits may either represent lagoonal or shoreface/offshore deposits. The basin configuration suggests the deposits to the southwest are lagoonal whereas the deposits to the northeast are nearshore/offshore. Cores are lacking in these areas so diagnostic confirmation of the environmental interpretation is difficult.

The northwest-southeast trending oil fields are dissected by northeast trending Channel Facies which are dominately shale-filled. Sandstone-filled channels occur in the region where the thickest B sandstone is developed. These channel-fill sand-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CELTIC
KITSCOTY
NORTHMINSTER
BLACKFOOT
LLOYDMINSTER
ABERFELDY
GULLY LAKE
EDAM WEST
EDAM
FURNESS
GOLDEN LAKE
RUSH LAKE
EPPING
WAINWRIGHT
MARSDEN SOUTH
ALBERTA
SASKATCHEWAN
CAMP WAINWRIGHT MILITARY RESERVE
RIVER
CHANNEL FACIES

Fig. 14 - Distribution of the Channel Facies with the major channel-fill sandstone deposits highlighted. All the well logs in the study area were reviewed to determine the log signature for grouping into the two major facies within the Sparky formation. The dashed lines indicate possible channels that are defined by only a few thick Channel Facies wells.

stones may be distributary channels and/or tidal inlet deposits. The shale-filled channels may represent abandoned distributary channels or portions of a lagoonal environment.

The A sandstone is commonly developed in the Aberfeldy and Golden Lake Fields. Major channels are in close proximity to these sandstone occurrences which are probably crevasse splay deposits. Elsewhere, the A sub-unit's shales and poorly sorted, silty sandstones are probably interdistributary bay deposits between distributary channels or lagoonal sediments behind thick shoreface sandstone. In proximity to the edge of the Prairie Formation, the Channel Facies has more numerous and thicker sandstone-filled channels with a greater areal extent than sandstone-filled channels to the west, suggesting a possible estuarine origin for these deposits.

Marsh deposits, represented by the Sparky coal, cap the entire sequence. To the northeast and east, the absence of the Sparky coal corresponds with the Prairie Formation depression, implying that the paleo-low influenced the Sparky coal's distribution.

(d) Depostional Model

The Sparky formation represents a regressive phase within the Mannville Group of the Lloydminster area. The basal Sparky is continuous across the Lloydminster Sub-basin implying that restricted marine conditions existed over the entire region after deposition of the General Petroleums formation. During C and D sub-unit deposition, areas of slightly higher relief, such as the Wainwright Ridge, had clastic sediments reworked by wave action into well sorted shoreface siltstones/sandstones (Fig. 15A). Interbedded sandstone, siltstone and shale were deposited throughout the remainder of the Lloydminster Sub-basin and indicate areas of slightly deeper shoreface to near shore sedimentation. During B sub-unit deposition (Fig. 15B), either lowering of sea level or an increased sedimentation rate resulted in northeastward progradation of shoreface deposits towards the area of the city of Lloydminster. Thick shoreface sandstone bodies were deposited in a general northwest-southeast trend. Distributary channel and/or tidal inlets dissected these thick shoreface deposits. Lagoonal mud and silt occur to the southwest of the shoreface deposits. In the Prairie Formation depression to the northeast and east, nearshore/offshore mud, silt and occasional sand beds accumlated. The final phase of the regression (Fig. 15C) had crevasse splay and overbank deposits filling interdistributary bays and/or lagoonal mud, silt and occasional sand occurring in the lee of shoreface deposits. Major sand-filled channels developed in the eastern part of the sub-basin and are possibly of estuarine origin. An extensive marsh environment existed over most of the Lloydminster Sub-basin but was absent to the northeast and east, probably due to continued marine conditions in the Prairie Formation depression. The depositional characteristics of the Sparky formation suggest a wave-dominated deltaic environment in the Lloydminster area.

TYPE OF HYDROCARBON TRAPS

INTRODUCTION

Heavy oil in the Lloydminster area has accumulated in stratigraphic and/or structural traps. Four main trap types are recognized in the Sparky formation:

Type A The Regional Facies abutting up-dip against the shale-filled Channel Facies (Vigrass, 1977),

Type B Structural reversal caused by salt disslution of the underlying Devonian Prairie Formation (Orr *et al.*, 1977),

Type C Sandstone-filled Channel Facies either abutting up-dip against non-reservoir rocks of the Regional Facies or shale-filled portions of the Channel Facies,

Type D Lateral pinch-out of the Regional Facies sandstones.

Types A and B are the two most important trapping mechansims.

Typically, heavy oil pay in the Regional Facies varies from 3 - 14m thick (Fig. 2). These area lie in the central part of the study area between the Paleozoic ridges and the Devonian Prairie Formation depression. Sandstone bodies in proximity to, and overlying, the Pre-Cretaceous ridges are thinner but can be productive, as is the case in the Wainwright field. Sandstone sub-units in the Prairie Formation depression are also thinner but are generally water-bearing. The sandstone-filled Channel Facies may have oil pays up to 40m thick (i.e. Home Oil's Kitscoty EOR Project: S/2 2-51-2W4M).

Sandstone/siltstone reservoirs in the Sparky formation have the following characteristics:

Porosity	27-33%; generally 30%
Permeability	500-8000 md; generally 1000-5000 md
Water Saturation	15-35%; generally 14-18°
API	10-25°; generally 20%
Viscosity	greater than 1000 cps; generally 3,000-10,000 cps

TYPE A: SHALE-FILLED CHANNEL FACIES

The shale-filled Channel Facies acts as the up-dip permeability barrier to hydrocarbon movement (Vigrass, 1977) within sandstones/siltstones of the Regional Facies (Fig. 11). They are primarily Sparky channel-fills. Waseca shale-filled channels (Fig. 13), however, have also eroded through part of all of the Sparky formation in some areas such as the Freemont Pool, Saskatchewan (Dunning *et al.*, 1980) and provide the up-dip trapping mechanism.

As illustrated in Figure 11 from the Aberfeldy Field, the Sparky shale-filled Channel Facies has eroded down into the lower portion of the General Petroleums formation and forms the up-dip trap for Regional Facies sandstones in both the Sparky and General Petroleums formations. The 3B7-20 well, from the Aberfeldy steamflood pilot, is a typical well log from the field, even though the area has been previously subjected to waterflooding. Regionally, oil is present in all four Sparky sub-units although this varies from pool to pool. The better development of reservoir quality sandstone/siltstones in the B and C sub-units results in these being the more productive sub-units.

TYPE B: DEVONIAN PRAIRIE FORMATION EDGE

Salt dissolution of approximately 160m of Devonian Prairie Formation has formed a reversal of dip (Orr *et al.*, 1977) in the eastern part of the study area (Fig. 4). This is the major trapping mechanism for the Celtic, Westhazel, Standard Hill, Rush Lake and Edam Sparky Fields. Structural relief in the order of 90m has caused oil trapping in other Mannville formations besides the Sparky formation. Figure 4 shows the southwesterly dip, and the thinning of the Prairie Formation salt to the east. In the areas of thin or no Prairie Formation the overlying formations are structurally low, causing hydrocarbons to be trapped in the structurally high areas.

TYPE C: SANDSTONE-FILLED CHANNEL FACIES

Within the Channel Facies, sandstone-filled portions have locally developed and traps from either against the shale-filled portions of the Channel Facies (Fig. 13) or against non-reservoir shale/siltstones of the Regional Facies. The oil in these sandstones is typically heavier than oil in the Regional Facies due to increased biodegradation of the oil. The Channel Facies sandstones are typically thicker, slightly coarser grained, better sorted, and have less clay than the Regional Facies sandstones but the increased viscosity of the oil and the presence of waterlegs have generally made them uneconomical to produce at this time. For this reason, many of these pools have sparse well control, making it difficult to ascertain the size and geometry of the sand body. Figure 14 depicts areas in which the authors have identified Sparky related channel-fill sandstones with oil pay.

A structural cross-section (Fig. 13) through the Rush Lake area of Saskatchewan illustrates the major characteristics of this type of trap. The Sparky coal overlies all the wells and the Channel Facies extends down into the Rex formation and in places, into the top of the Lloydminster formation. A local channel-filled sandstone has developed at the base of the Channel Facies and is encased by shale-filled portions of the Channel Facies and shales of the Rex formation. Local sandstone bodies and thin sandstones, stratigraphically equivalent to the Sparky B, C and D sub-units, occur in the upper part. As previously mentioned, they may represent late sand influxes during channel abandonment or migration of the Sparky sub-units over an in-filled channel.

TYPE D: LATERAL PINCH-OUT OF REGIONAL FACIES SANDSTONE

This type of trap is of minor importance and is more common locally within pools where one or more sandstone sub-units grade laterally into non-reservoir shale/siltstone. At Marsden, Saskatchewan (Fig. 16), the Sparky B, C and D sub-units grade up-dip into non-reservoir shale/siltstone with minor tight sandstone beds. Down-dip at A6-10-44-27W3M, the Sparky C and D sub-units are completely wet and the Sparky B sandstone sub-unit is tight.

SUMMARY

The Base of Fish Scale Zone to pre-Cretaceous unconformity surface isopach map thickens to the northeast and east into a structural low caused by salt dissolution of the underlying

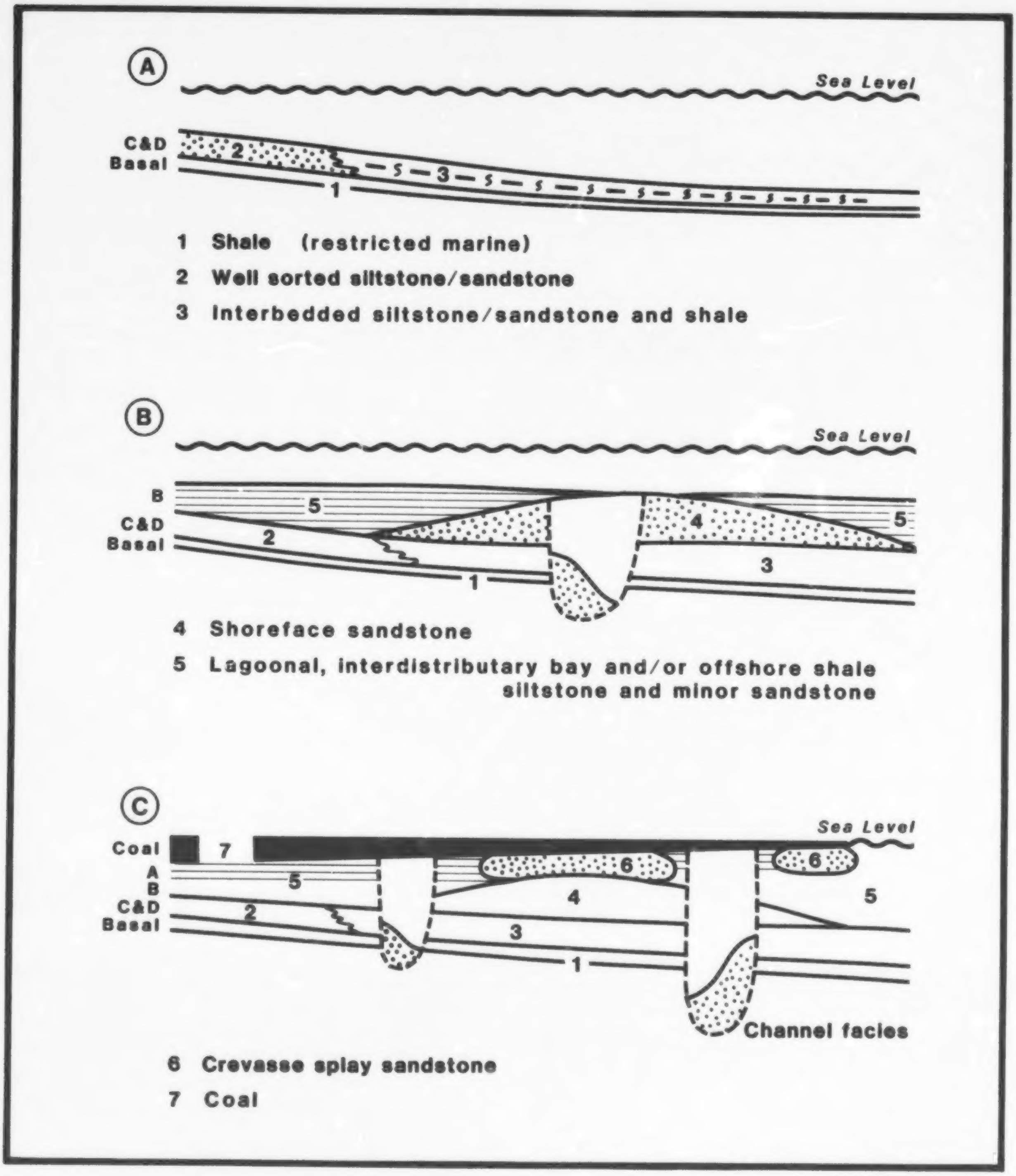
A
Sea Level
C&D
Basal
2
3
1
1 Shale (restricted marine)
2 Well sorted siltstone/sandstone
3 Interbedded siltstone/sandstone and shale
B
Sea Level
B
C&D
Basal
5
2
4
5
3
1
4 Shoreface sandstone
5 Lagoonal, interdistributary bay and/or offshore shale siltstone and minor sandstone
C
Sea Level
Coal
A
B
C&D
Basal
7
5
6
6
4
5
2
3
1
Channel facies
6 Crevasse splay sandstone
7 Coal

Fig. 15 - Regressive wave-dominated deltaic model for the Sparky formation. a) C and D sub-unit: wave reworking of sediments into shoreface deposits. b) B sub-unit: Thick shoreface sediments were deposited with a northwest-southeast trend and were dissected by distributary channels and/or tidal inlets. Lagoonal sediments accumulated to the southwest while offshore/shoreface sediments were deposited in the northeast. c) A sub-unit and Sparky coal: Final phase of regression with distributary channels eroding through pre-existing Sparky sediments. Interdistributary bay and crevasse splay deposits occur between the channels in the upper part of the Sparky formation. Marshes formed over most of the Lloydminster area.

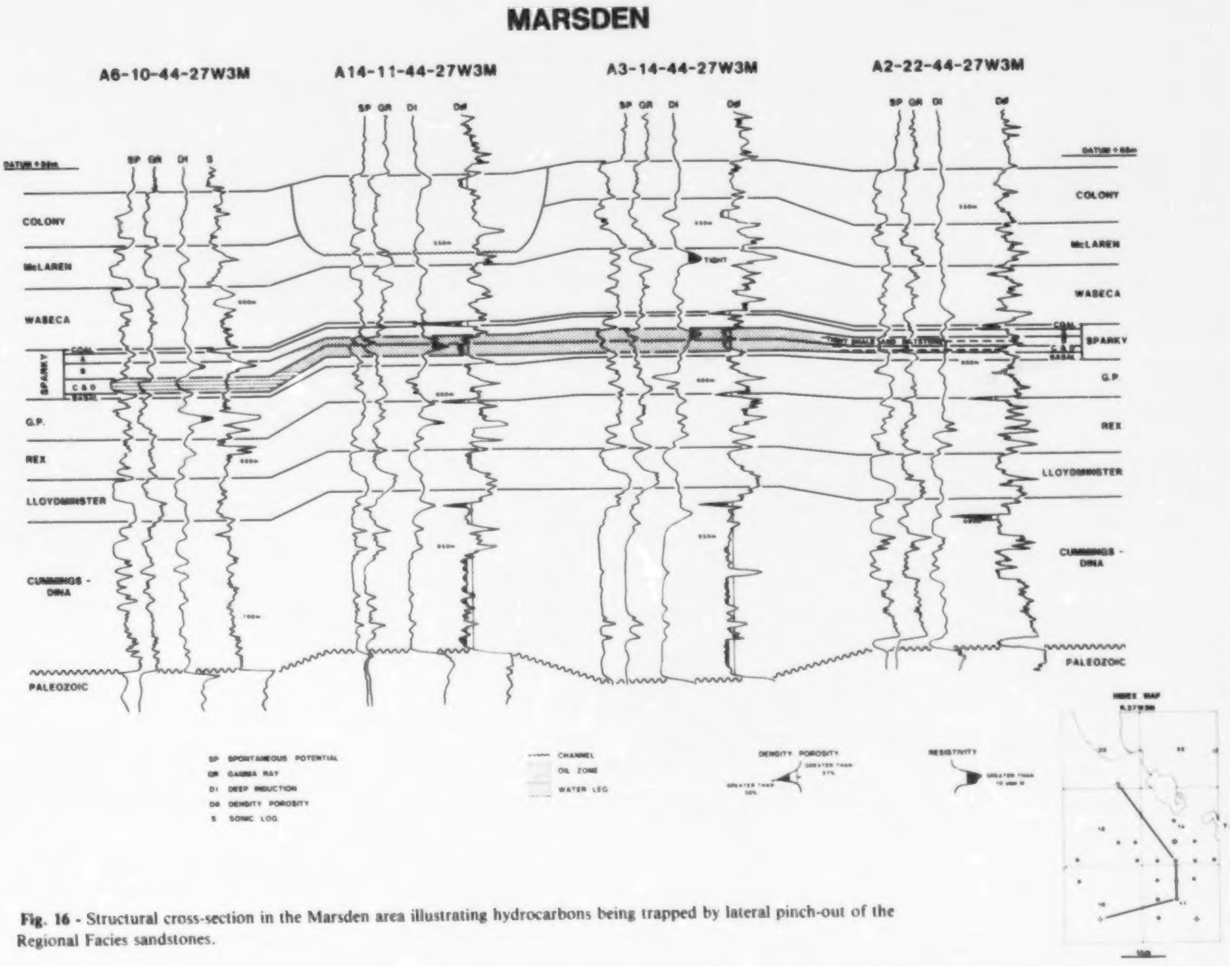
MARSDEN
A6-10-44-27W3M
A14-11-44-27W3M
A3-14-44-27W3M
A2-22-44-27W3M
SP GR DI S
SP GR DI D⌀
DATUM
COLONY
McLAREN
WASECA
SPARKY
COAL
A
B
C & D
BASAL
G.P.
REX
LLOYDMINSTER
CUMMINGS - DINA
PALEOZOIC
TIGHT
INDEX MAP
SP SPONTANEOUS POTENTIAL
GR GAMMA RAY
DI DEEP INDUCTION
D⌀ DENSITY POROSITY
S SONIC LOG
CHANNEL
OIL ZONE
WATER LEG
DENSITY POROSITY
GREATER THAN 30%
RESISTIVITY

Fig. 16 - Structural cross-section in the Marsden area illustrating hydrocarbons being trapped by lateral pinch-out of the Regional Facies sandstones.

Devonian Prairie Formation and thins over Devonian Woodbend Formation carbonate ridges to the southwest, south, and north. These ridges outline the Lloydminster Sub-basin and are referred to as the Wainwright Ridge, Baldwinton Ridge, and Lindbergh Ridge respectively. It is suggested that deposition of the Sparky formation has been influenced by the basin configuration of the pre-Cretaceous unconformity surface.

The second order residual maps of the pre-Cretaceous unconformity surface and the Sparky formation also depict the major structural elements bordering the sub-basin, suggesting the pre-Cretaceous basin configuration influenced Sparky deposition. The relationship is further illustrated by the edge of the Sparky coal, which generally coincides with the edge of the Devonian Prairie Formation in the east. This structural low was probably present during Sparky deposition and has restricted marsh development due to the continued existence of marine waters. Thickening of the Sparky coal in the Wainwright area occurred in a slowly subsiding lagoon or interdistributary area during the last stage of deposition within the Sparky formation. Extensive channeling in the center of the sub-basin is related to channel migration and abandonment. Thicker and more widespread sandstone-filled channels occur adjacent to the edge of the Prairie Formation salt and may be of estuarine origin. Most of the Sparky oil fields occur in the center of the sub-basin and are interpreted to be shoreface sandstone/siltstones.

Structural and/or stratigraphic traps are present in the Lloydminster heavy oil area. The most important trapping mechanisms for the Sparky formation are:

(a) Shale-filled Channel Facies forming the up-dip seal for the Regional Facies sandstones,

(b) Salt dissolution of the underlying Devonian Prairie Formation has caused structural reversal in the Celtic/Westhazel/Edam area.

Locally, the development of Channel Facies sandstones and lateral pinch-out of Regional Facies sandstones are possible Sparky hydrocarbon traps.

ACKNOWLEDGMENTS

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PALEOENVIRONMENTAL INTERPRETATION OF THE LOWER CRETACEOUS WASECA FORMATION, UPPER MANNVILLE GROUP, LLOYDMINSTER AREA, SASKATCHEWAN

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ABSTRACT

Analysis of 1500m of core from 70 wells in the Lloydminster area, Saskatchewan was undertaken. Cored wells were examined from four heavy oil fields: Pikes Peak, Lashburn, Gully Lake, and Golden Lake. To supplement core data, approximately 300 geophysical well logs were studied. Cored intervals are primarily from the Waseca formation within the Lower Cretaceous Mannville Group, constituting 1200m of the 1500m total. The Waseca formation contains an anomalously thick (up to 35m), laterally shale bound, north-south trending sand body that is 0.8-2.7km wide and at least 30.2km long.

A brackish water, inland coastal setting is indicated by the sedimentology and associated paleontology. The sand body is sheet-like in cross section and is recognized as having been deposited in a wide, shallow channel. Although the channel experienced some lateral migration, vertical aggradation is inferred to have been more significant in sand accumulation. The sand body is not a valley-fill deposit.

The above features do not fit a purely fluvial model and are best explained by a tidal channel or estuary. An estuary is envisaged for the Waseca sand body, particularly since its 30.2 km length and abundance of undirectional current structures in the deposit further south suggest some fluvial input into the system.

Current research will attempt to refine this model and define the relationships, if any, between this reservoir body and those laterally adjacent, thus providing a more reliable basis for future exploration.

INTRODUCTION

General Statement:

In the Lloydminster area of Saskatchewan, the Lower Cretaceous Mannville Group comprises a complex sequence of poorly consolidated sands, shales, mixed sands and shales and minor coals and conglomerates. Studies of the micropaleontology and paleobotany of the Mannville indicate an Aptian to middle Albian age (Christopher, 1974). Within this area, the Mannville Group unconformably overlies the Devonian Duperow Formation, and is in turn overlain by a thick accumulation of marine shales of the Lower Colorado Group.

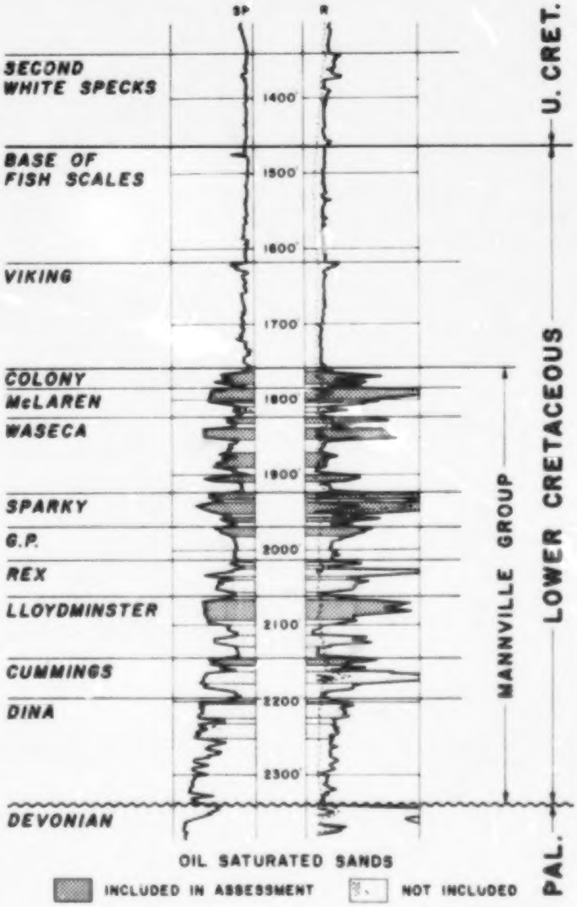


Fig. 1 - Stratigraphic nomenclature for the Mannville Group, Lloydminster area, (after Orr, *et al.*, 1977).

The Mannville Group has been divided into nine informal units (Fuglem, 1970), later informally termed members (Vigrass, 1977), or formations (Orr *et al.* 1977) on the basis of electric log characteristics (Fig. 1). No type sections have been described for the seven upper formations. For the purpose of this paper, the units are given informal formation status. This study is concerned with the upper Sparky, Waseca, and lower McLaren formations, which, in the Lloydminster area, have been variously interpreted as fluvial environments (Vigrass, 1977; Putnam, 1980, 1983), coastal environments (Lorsong,1979; Haidl, 1980; Maccagno and Watson, 1980), or a combination of the two (Christopher, 1980; Orr *et al.*, 1977).

Study Area and Method of Study

The study area encompasses T 47-48, R 22W3; T 47-50, R 23W3; and T 48-50, R 24W3 (Fig. 2). Approximately 1500m of core, 1200m of which is from the Waseca formation, from 70 wells in the area were analysed during the course of this study. The cored wells are concentrated into four heavy oil fields: Pikes Peak (29 wells); Lashburn (4 wells); Gully Lake (11 wells); and Golden Lake (26 wells). More than 300 geophysical well logs have been studied also, in order to offset the lack of even core distribution and to provide correlation between cored wells.

LITHOFACIES DESCRIPTION

The lithofacies classification adopted here is modified after Lorsong, 1979. The classification is based upon lithology and primary sedimentary structure. For the purpose of measuring sections, a 20cm lower limit of lithofacies unit thickness was found to be convenient in most cases.

Sand lithofacies, (lithofaces L, T, M, and R) are generally composed of very fine to fine quartz grains. The sands are typically well sorted, although some facies, particularly lithofacies T and R, may contain considerable amounts of silt and clay. Well sorted sands are often oil saturated unless cemented. Oil saturation decreases with increasing silt and clay content.

The interbedded sand and shale lithofacies (lithofacies B), likewise contains very fine to fine quartz sand which is often well sorted and oil saturated. The silt and shale lithofacies (lithofacies S2) is not oil stained. Both lithofacies B and S2 are characterized by sand or silt oscillation and/or unidirectional and multidirectional (current formed) ripples. Oscillation rip-

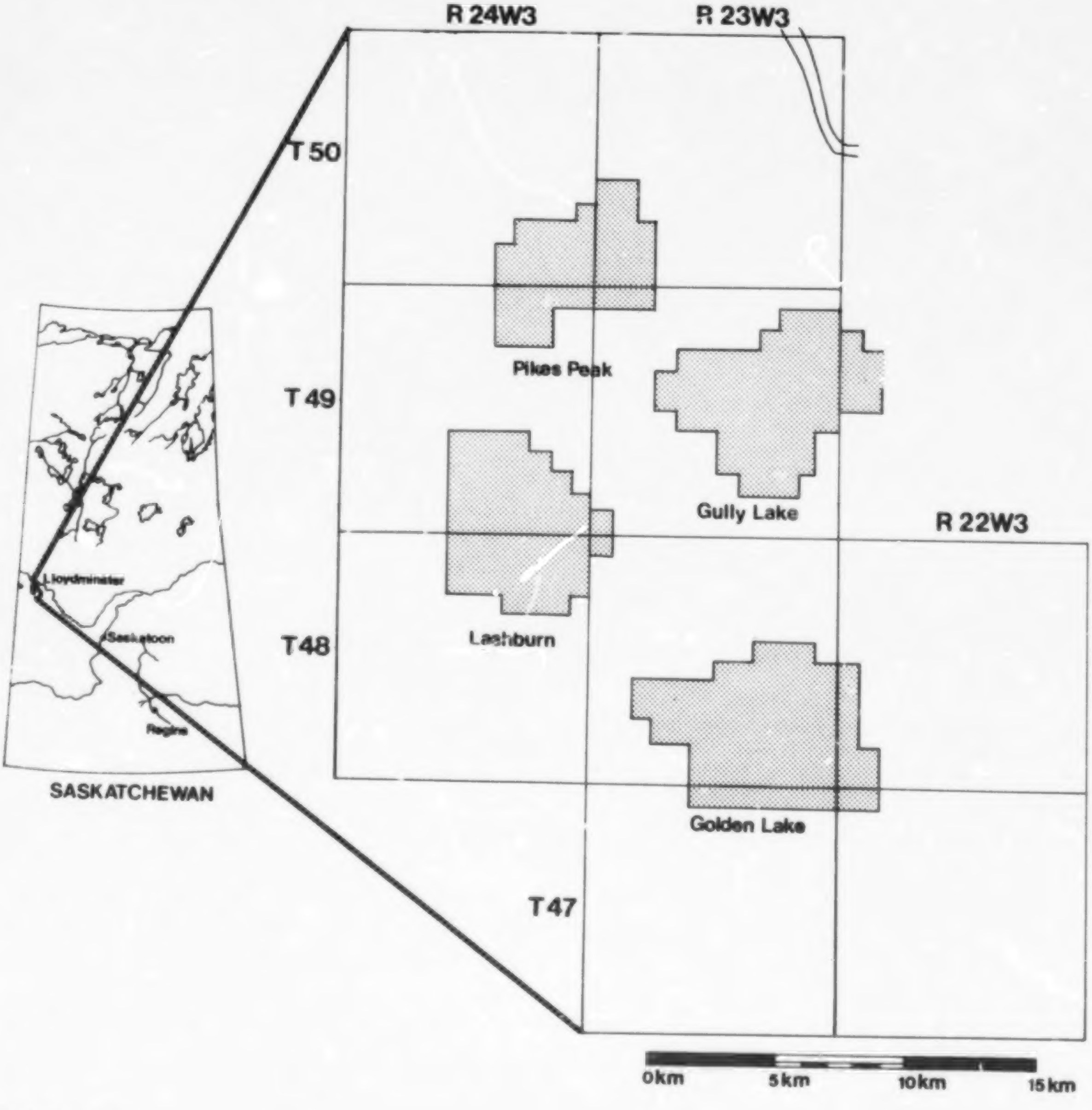

R 24W3
R 23W3
R 22W3
T 50
T 49
T 48
T 47
Pikes Peak
Gully Lake
Lashburn
Golden Lake
Lloydminster
Saskatoon
Regina
SASKATCHEWAN
0km
5km
10km
15km

Fig. 2 - Study area.

ples predominate in the northern part of the study area with lesser multidirectional forms. Unidirectional ripples become more abundant to the south. Ripples in lithofacies S2 are significantly smaller than those in lithofacies B. In addition, syneresis cracks, characterized by low width/length ratios, are locally common in the shales of these lithounits. Syneresis cracks (Fig. 3 I, J) are formed by salinity changes in the fine grained sediments of lake, lagoon and tidal mudflat (fresh to brackish water) environments. Lithofacies S1 is a shale unit distinguished from lithofacies S2 by its lack of discrete silt interlaminae. Lithofacies C (coal) is the final lithounit recognized in the core.

Lithofacies L: Lithofacies L is characterized by planar lamination, generally with an inclination of less than 10° (Fig. 3A). Rare units exhibit multidirectional lamination in wedge-shaped sets, with laminae conformable to erosional surfaces (swash-zone lamination). Occasionally, sets fan upward to or from the horizontal. Less commonly, sets exhibit steeper cross lamination of up to 35° (Fig. 3B). Thin (less than 20cm, by convention) units of ripple laminated sand, often containing considerable amounts of silt and clay, may be intercalated. The ripple laminae, frequently marked by finely comminuted plant debris, are typically multidirectional.

Lithofacies T: Lithofacies T units (Fig. 3C) are essentially identical to ripple laminated sets within lithofacies L, but thicker than 20cm. Ripple types are often indeterminate; of the identifiable forms, oscillation and multidirectional ripples appear to predominate in the north, becoming less common southward, where unidirectional forms become abundant. Small scale trough cross lamination (Fig. 3D), often with intercalated silt, clay, and finely comminuted plant debris, is largely restricted to the southern part of the study area.

Lithofacies M: Lithofacies M units (Fig. 3E) are massive (apparently structureless) sands which comprise the main reservoir in the northern part of the study area. In rare instances, considerable amounts of silt and clay may be present. Individual clay clasts are frequently included in the sand. In addition, thin (less than 20cm) low angle planar laminated sands may also be intercalated. The structureless nature is problematic; it may be due to the sand's being originally deposited in a structureless state; the oil saturation, which has obscured existing structure; intense bioturbation, which has homogenized the sand units and hence destroyed original structures; and/or, the well elutriated nature of the sand, which has provided little clay material to mark the laminae. An X-radiograph of a cored section through such a sand unit, by Husky Oil, has revealed no obvious hidden structure.

Lithofacies R: Lithofacies R is an intraformational conglomerate unit, (Fig. 3F) with a sand matrix and clasts of various sizes, composed predominantly of facies S2 shale and lesser numbers of carbonate and pyritic nodules and coalified wood. The clasts range from subangular to subrounded, with abraded surfaces. The units are generally structureless, although inverse or normal grading locally occurs. The units range from matrix to clast supported, averaging 43.1% clasts, and 56.9% matrix. A small proportion of lithofacies R units contain only clasts of residual material; such units are lag deposits.

Lithofacies B: Lithofacies B comprises interbedded sand and shale units. (Fig. 3G) These units are characterized by lenticular bedded oscillation and multidirectional/unidirectional (current) ripples, with lesser wavy to flaser bedding (cf. Reineck and Wunderlich, 1968). Lithofacies B units are typically moderately to intensely bioturbated, burrowing being more common than rooting. Interbedded shales, typically with discrete silt laminae, and of varying carbonaceous content, drape the sand bedform shapes. Carbonaceous detritus and occasional coal spar may be present throughout, but are more common in the southern part of the study area.

Lithofacies S1: Lithofacies S1 is characterized by essentially massive (structureless) shales of varying carbonaceous content, often containing considerable amounts of interstitial silt. Root zones (Fig. 3H) are commonly developed in this lithofacies. Some S1 units may be biogenically homogenized lithofacies S2 units. This is probably the case where intensely bioturbated S2 units are in gradational contact with S1 units. Lithofacies S1 is numerically and volumetrically rare in the study area.

Lithofacies S2: Lithofacies S2 comprises grey to black shales with discrete laminae or beds of white silt. These silts commonly form pinstripe (horizontally) bedded units (Fig. 3I), with lesser lenticular bedding (cf. Reineck and Wunderlich, 1968). Bioturbation, principally burrowing, is common to this lithounit and ranges from weak to intense. Locally, rooting disturbs the primary structure as well.

Lithofacies C: Lithofacies C units are composed of lignitic to sub-bituminous coals (Fig. 3H). Macroscopically, the coals are dull, with occasional bright bands. Fusain pods are locally abundant. Considerable volumes of intercalated or interstitial clastic debris are often present. Complete gradation between carbonaceous shales and coal can be found in the study area. Pyritic nodules are frequently associated.

LITHOFACIES INTERPRETATION

Each lithofacies (described above) has been interpreted by various researchers to form in a wide variety of environments (Table 1). Detailed study of the geometry and vertical sequence of lithofacies greatly limits the range of possible environments. It has been recognized (Haidl, 1980), however, that only within densely cored areas (i.e., those with a 5 acre well spacing) with continuous core, can such detailed geometries and vertical sequences be developed to the extent of envisaging a 3-dimensional model.

Unfortunately, the present study area has in general, a 20 acre or more spacing of core, within four fairly isolated areas, and with core seldom continuous through the study interval. Integration of geophysical well log information does, to a limited extent, alleviate this problem. For all practical purposes, only four general lithotypes (types X, Y, Z and C) can be defined on the basis of geophysical well log characteristics (Haidl, 1980). Table 1 shows the relationship between these lithotypes and the lithofacies observed in core. It becomes obvious that lithotypes determined from well logs can represent a much wider range of depositional environments. Haidl (1980) also notes that geophysical well log responses do not accurately reflect the true nature or complexity of the sequence that may be observed in core. As a result, only a generalized picture of the vertical succession and the geometries of the lithofacies can be obtained, even when combining core and well log data. Any paleoenvironmental interpretation must, therefore, be general in nature.

Paleontologic Constraints

Improvements on the lithofacies interpretation can be made using paleontologic data obtained from core. Since some organisms are extremely sensitive to changes in the environment, paleontology is useful in narrowing the range of potential depositional environments of each lithofacies. Within Mannville sediments, ichnofossils are the most abundant of the paleontologic indicators and therefore, potentially the most useful. Megafossils are exceedingly rare in the Mannville, being present in only a few cores in the Lloydminster area (i.e. the Marsden Field, Lorsong pers. comm.) No megafossils were recognized in core from the study area. Palynology does not figure extensively in the literature referring to the Lloydminster area of Saskatchewan, although considerable work has been accomplished in Mannville Group and equivalents in Alberta (cf. Singh, 1964, 1971). In the study area, palynomorphs are well preserved but are relatively low in number and diversity. Paleoenvironmental work on Mannville coals has also been largely ignored. Recent work by Groeneveld and Stasiuk (this volume), however, shows the usefulness of coal studies in defining the general sedimentary setting.

Ichnology: Ichnology has, in recent years, been recognized as an indicator of depositional environments (Chamberlain, 1978; Basan, 1978). As many individual forms may cross environmental boundaries (Basan, 1978), assemblages of trace fossils are more useful in establishing a depositional environment. Bioturbation, principally burrowing, is virtually ubiquitous within Mannville sediments. The author has tentatively identified some genera (*Ophiomorpha, Skolithus*) as existing within the moderately diverse ichnofauna present in the sediments. These forms suggest a near coastal environment (Chamberlain, 1978). In more general terms, intense burrowing is characteristic of marine to brackish water environments, where: (a) a low sedimentation rate persists; (b) there is a high faunal density; and/or (c) minimal physical reworking of the sediment occurs.

Body Fossils: Calcareous body megafossils are almost wholly absent from the Mannville sediments. Pervasive burrowing, as described above, demonstrates the presence of an active and probably abundant infauna, so it is reasonable to assume that calcareous macroinvertebrates were also abundant.

Studies by Peterson (1976) concerning two Californian lagoons (Mugu and Tijuana Slough) characterized by marine to brackish water have shown that shell dissolution procedes relatively rapidly. Their persistence in the environment ranges from 4 to 894 years with most forms persisting less than 200 years. The megafossils from the Marsden Field are entirely thin walled gastropods; these shells have a large surface area to weight ratio and are, therefore, more susceptible to dissolution than those with small ratios. Presuming such forms to be common in the Mannville, the absence of calcareous macroinvertebrate fossils is easily explained.

The lack of shell molds and casts indicates that shell dissolution must have occurred while the sediments were still plastic. Additionally, this dissolved carbonate may be the source of carbonate cements locally present in the Mannville sediments (Lorsong, 1981) although the presence of thick carbonate sequences underlying the Mannville would also provide the necessary cements. Yeo and Risk (1981) affirm that complete shell dissolution may occur within 15cm of the sediment/water interface in modern marine to brackish water settings. Dissolution rates may be enhanced by the physical breakage of shells or from biogenic predation. In any case, the absence of calcareous body fossils is in keeping with a marine to brackish water setting, and does not suggest that the sediments were deposited in a biologically unproductive environment.

Palynology: Preliminary analysis of selected samples shows an assemblage dominated by terrestrial forms, such as *Appendicisporites, Cicatricosisporites, Trilobosporites,* conifer saccate grains, and occasional megaspores (Nambudiri, pers. comm.). In this study, no attempt to determine species was made. Conifer saccate grains, although indicative of coniferous (terrestrial) forests, are readily transported considerable distances. The assemblage has a high proportion of herbaceous forms, which is not inconsistent with a salt marsh vegetation. Locally, *Equisetosporites,* an aquatic form that is common in coastal swamps, is present. Dinoflagellates and acritarchs (*Hystrichosphaeridium* and *Baltisphaeridium)* are locally present and may account for as much as 6% of the sample. Although the proportion of marine forms does not indicate true marine conditions, their presence does indicate at least some marine influence in the study area.

Coal Studies: Associated root zones show hair-like carbonaceous traces (Fig. 3H), typical of salt marsh vegetation, rather than thick coaly traces distinctive of woody forest vegetation (Ruby *et al.*, 1981). Petrographic work and proximate and sulphur form analyses of the coals are expected to demonstrate a predominantly salt marsh (brackish water) setting.

From the paleontologic constraints, it follows that the potential environments for the lithofacies must be consistent with a largely brackish water setting. Several depositional environments can therefore be eliminated with some degree of confidence (Table 2). The range of potential environments that remain fall within an inland coastal (coastal plain) setting.

THE WASECA SAND BODY: DESCRIPTION

The Waseca sand body overlies a fining upward sequence grading from ripple laminated and low angle planar laminated sands, through interbedded sands and shales, to silts and shales, and is typically capped by a laterally extensive, but thin (<1 m), coal. This upward fining trend, generally less than 10m thick, characterizes the upper Sparky formation.

The Waseca sand body, in turn, is overlain by a coarsening upward sequence of discretely laminated silts and shales, interbedded sands and shales, and moderate to well sorted ripple or planar laminated sands, comprising the lower McLaren formation. This upward coarsening sequence is generally less than 10m thick. Frequently, the contact between the Waseca and McLaren formations is gradational.

Fig. 3 - A. Lithofacies L: densely oil stained, low-angle planar cross laminated sand. Note the thin ripple laminated set near the top. Core has fractured along clay interlaminae.

B. Lithofacies L: high angle planar cross lamination. Differential oil staining, as a result of clay cementation, marks the laminae.

C. Lithofacies T: a complex series of ripple-laminated, clay cemented, silty sand. Differential oil staining and finely comminuted plant debris mark the laminae.

D. Lithofacies T: small scale trough cross laminated, clay cemented sand. Laminae are marked by differential oil staining and finely comminuted plant debris.

E. Lithofacies M: oil saturated, apparently structureless (massive) sand.

F. Lithofacies R: matrix-supported intraformational conglomerate. The sand matrix is oil saturated.

G. Lithofacies B: lenticular bedded sand and shale. Oil saturated sand ripples (dark) are draped by shale laminae (light).

H. Lithofacies S1 and C: structureless light grey shale, with abundant hair-like root traces. A sub-bituminous (?) coal overlies this root zone.

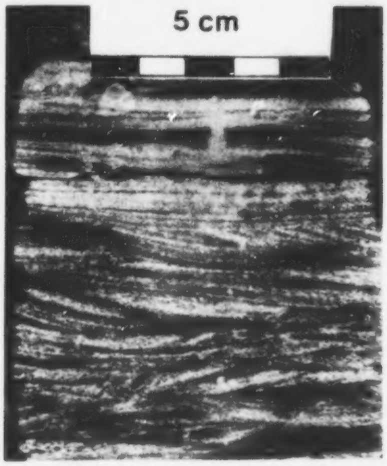
I. Lithofacies S2: pinstripe-laminated white silt with interlaminated grey shale. Note the abundant ptygmatically folded, silt-filled syneresis cracks. The folding is the result of post-depositional compaction.

J. Syneresis cracks: a plan view of the syneresis cracks demonstrates that they are haphazard in orientation unlike desiccation cracks which form polygonal patterns.

A

B

C



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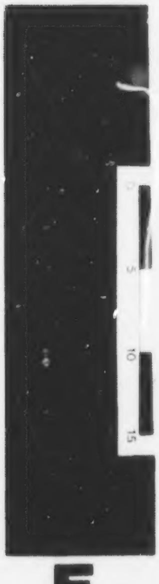

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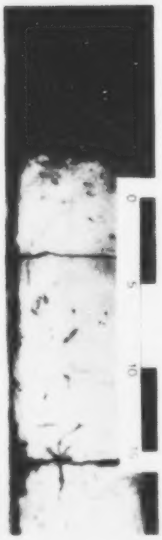

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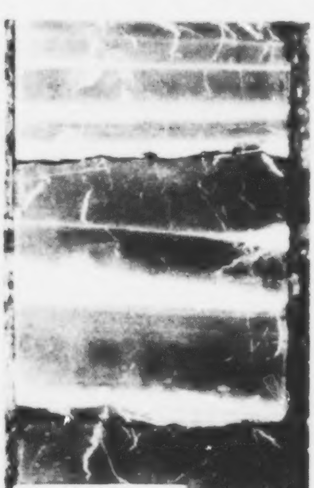

I

J

Log Lithotype (Haidl 1980)	Lithofacies	Potential Environments	Reference
Type Z (Shaly Sands = Z or Y)	M	exposed areas of embayment shoals, beaches, tidal deltas, tidal/fluvial channel bottoms, tidal/fluvial point bars, shelf sand, scour pockets on distributary mouth bars, any of facies L or T	Ruby et. al. 1981; Orr et. al. 1977; Lorsong, 1979
	M + coal	tidal/fluvial channels, tidal/fluvial point bars, distributary mouth bars, splay deposits, Rarer: tidal inlet fills, embayment shoals	
	R	storm lag deposits, tidal/fluvial channel lags, tidal/fluvial channel margins (adjacent to cutbanks), tidal flat channel margins (adjacent to slump blocks), storm channels	Ruby et. al. 1981
	L	Low L: beachface/foreshore, exposed embayment shoals, upper portions of tidal deltas, washovers, tidal/fluvial point bar crests, fluvial/tidal channel bottoms, distributary mouth bars, transverse bars	Lorsong, 1979 Ruby et. al. 1981; Orr et. al. 1977 Reineck and Singh, 1980
	L	High L: embayment shoals, beaches, fluvial/tidal point bars, fluvial/tidal channel bottoms, distributary mouth bars, tidal deltas, shelf sand ridges	
	L + coal	embayment shoals, fluvial/tidal point bars, fluvial/tidal channel bottoms, distributary mouth bars, crevasse splays	
	T	sandy tidal flats, beachface/shoreface, embayment shoals, crevasse splays, washovers, fluvial/tidal channels, fluvial/tidal point bars, distributary mouth bars, interdistributary delta front, offshore-storm wave base	Ruby et. al. 1981
Type Y + Z	B sa	middle-upper fluvial/tidal point bars, fluvial/tidal channel margins, embayment shoals, distal crevasse splays, back barrier lagoon, interdistributary delta fronts, mixed sand and mud tidal flats, offshore (near fairweather wave base)	Ruby et. al. 1981; Lorsong 1979; Reineck and Singh, 1980; Reineck and Wunderlich, 1968; Galloway and Hobday, 1983
Type Y	B sa + coal	fluvial/tidal point bars, fluvial/tidal channel margins, levees, distal crevasse splays, embayment shoals, back barrier lagoons, interdistributary delta fronts.	
	B 50/50	low energy portions of fluvial/tidal point bars, mixed sand and mud tidal flats, back barrier lagoons, distal crevasse splays, subtidal embayment shoals, interdistributary bays, delta fronts, offshore (near fairweather wave base)	
	B 50/50 + coal	flood lake basins, interdistributary bays, distal crevasse splays, delta fronts. Rarer: tidal/fluvial point bars, mixed sand and mud tidal flats, lagoons, embayment shoals, offshore (near fairweather wave base)	
Type Y + X	B sh	upper portions of tidal/fluvial point bars, subtidal zones of mixed sand and mud tidal flats, back barrier lagoons, distal fringes of crevasse splays, subtidal embayment shoals, interdistributary delta fronts, bays, prodeltas, offshore (near or below storm wave base)	
Type X + Y	S2	upper portions of tidal/fluvial point bars, intertidal-subtidal mudflats, distal portions of crevasse splays, interdistributary bays, lagoons, lagoonal swamps, prodeltas, subtidal embayment shoals, offshore (near storm wave base)	Reineck and Wunderlich, 1968; Ruby et. al. 1981
Type X	S1	interdistributary bays, back barrier lagoons, abandoned tidal/fluvial channel fills, lake bottoms, prodeltas, offshore (below storm wave base), biogenically homogenized lithofacies S2	Ruby et. al. 1981; Lorsong 1979; Orr et. al. 1977
	S1 + roots/coal	floodplains, backswamps, lower levees, interdistributary bay fringes, marshes, swamps, interdistributary delta fronts, abandoned fluvial/tidal channel fills, lake shores, embayment margins, higher portions of tidal mudflats, fluvial/tidal channel overbank deposits, biogenically homogenized rooted S2	
Type C	C	swamps, marshes, interdistributary upper and lower delta plains, fluvial backswamps	Ruby et. al. 1981
	C + sh	swamps, delta plains (near distributaries) backswamps (adjacent to tidal/fluvial channels), marshes	

Table 1 - Lithofacies vs. potential environments of deposition.

Log Litho-type (Haidl 1980)	Litho-facies	Potential Environments	Reference
Type Z (Shaly Sands = Z or Y)	M	beaches, tidal channel bottoms, tidal point bars, scour pockets on distributary mouth bars, any of facies L or T	Ruby et. al. 1981; Orr et. al. 1977; Lorsong, 1979
	M + coal	tidal channels, tidal point bars, distributary mouth bars, splay deposits	
	R	storm lag deposits, tidal channel lags, tidal channel margins (adjacent to cutbanks), tidal flat channel margins (adjacent to slump blocks), storm channels	Ruby et. al. 1981
	L	Low L: beachface/foreshore, washovers, tidal point bar crests, channel bottoms, distributary mouth bars transverse bars	Lorsong, 1979 Ruby et. al. 1981; Orr et. al. 1977 Reineck and Singh, 1980
	L	High L: beaches, tidal point bars, tidal channel bottoms, distributary mouth bars	
	L + coal	tidal point bars, tidal channel bottoms, distributary mouth bars, crevasse splays	
	T	sandy tidal flats, beachface/shoreface, crevasse splays, washovers, tidal channels, tidal point bars, distributary mouth bars	Ruby et. al. 1981
Type Y + Z	B sa	middle-upper tidal point bars, tidal channel margins, distal crevasse splays, back barrier lagoon, mixed sand and mud tidal flats	Ruby et. al. 1981; Lorsong 1979; Reineck and Singh, 1980; Reineck and Wunder-lich, 1968; Galloway and Hobday, 1983
	B sa + coal	tidal point bars, tidal channel margins, levees, distal crevasse splays, back barrier lagoons	
Type Y	B 50/50	low energy portions of tidal point bars, mixed sand and mud tidal flats, back barrier lagoons, distal crevasse splays, interdistributary bays	
	B 50/50 + coal	flood lake basins, interdistributary bays, distal crevasse splays, Rarer: tidal point bars, mixed sand and mud tidal flats, lagoons	
Type Y + X	B sh	upper portions of tidal point bars, subtidal zones of mixed sand and mud tidal flats, back barrier lagoons, distal fringes of crevasse splays, bays	
Type X + Y	S2	upper portions of tidal point bars, intertidal-subtidal mudflats, distal portions of crevasse splays, interdistributary bays, lagoons, lagoonal swamps	Reineck and Wunderlich, 1968; Ruby et. al. 1981
Type X	S1	interdistributary bays, back barrier lagoons, abandoned tidal channel fills, lake bottoms, biogenically homogenized lithofacies S2	Ruby et. al. 1981; Lorsong 1979; Orr et. al. 1977
	S1 + roots/ coal	floodplains, backswamps, lower levees, interdistributary bay fringes, marshes, swamps, abandoned tidal channel fills, lake shores, embayment margins, higher portions of tidal mudflats, tidal channel overbank deposits, biogenically homogenized rooted S2	
Type C	C	swamps, marshes, interdistributary upper and lower delta plains, fluvial backswamps	Ruby et. al 1981
	C + sh	swamps, delta plains (near distributaries) backswamps (adjacent to tidal channels), marshes	

Table 2 - Lithofacies vs. potential environments of deposition in the study area.

The Waseca formation contains an anomalously thick (up to 35m), laterally shale bound, north-south trending sand body, 0.8-2.7km wide and at least 30.2 km in length, originally delineated by Lorsong and Wilson (1981, unpublished data) (Fig. 4).

Poor well control to the south prohibits further delineation in that direction. In Pikes Peak the Waseca sandbody is the main reservoir, containing $11.057 \times 10^6 m^3$ of oil in place (Sask. Energy and Mines, Reservoir Annual 1982, 1983).

In core, the sand body is characterized by a thick sequence of structureless sand (lithofacies M), with rarer, thin ripple laminated and small scale trough cross laminated sand (Lithofacies T) and low angle, planar laminated sand (Lithofacies L). Intrafromational and rare lag conglomerates (Lithofacies R) are locally abundant. The sand body is capped by an upward fining sequence of interbedded sand and shale units and discrete structureless sand beds.

Although cored zones are statistically biased in that reservoir sands are the most actively sought and, hence, penetrated lithounits, a survey of numerical and volumetric proportions is useful in characterizing the lithofacies in geographic areas and stratigraphic levels. Lithofacies M is a relatively minor lithounit in most surrounding areas (Lorsong, 1980; Haidl, 1980), generally accounting for less than 5% of the core. In contrast, the study area contains 30.44% (vol) of lithofacies M, 90.8% (vol) of it occurring within the Waseca sand body. Lithofacies R is entirely restricted to the Waseca formation, 98.7% (vol) of it occurring within the Waseca sand body, in the northern part of the study area. In the south (Golden Lake) the sand body is characterized by small scale trough cross laminated and current rippled sands (lithofacies T), accounting for 74.4% (vol) of the sand body.

On geophysical well logs, the Waseca sand body is a distinctive signature compared to the "average" Waseca signature typical of much of the study area (Fig. 5). The Waseca sand body is a thick, usually single sand unit capped by upward fining mixed sands and shales which grade into interlaminated silts and shales. Laterally adjacent to the Waseca sand body, thick accumulations of mixed sands and shales and silty shales contrast sharply with the "average" signature. The "average" signature is characterized by up to four discrete sand beds, generally upward coarsening and separated by interbedded sand and shale or silty shale. In the southern part of the study area (Golden Lake), the thick shale accumulations laterally bounding the sand body are largely absent.

THE WASECA SAND BODY: INTEPRETATION

The Waseca sand body lies upon the upper Sparky formation, where lithologies, vertical sequence, extensive lateral continuity, and paleontology seem to represent a progradation of subtidal sands, subtidal-intertidal mixed sands and muds, intertidal muds and ultimately supratidal salt-marsh/swamp environments.

In the northern part of the study area, the sand body is overlain by a sequence representing a return to intertidal sands, grading up into subtidal/intertidal mixed sands and muds, to subtidal sands of the McLaren formation. Palynologic data shows a higher percentage of marine forms in this sequence

The Waseca sand body's "shoestring" geometry (Fig. 4) suggests a channel environment. The sand body is predominantly structureless in nature and although various authors describe such sands as channel-fills (Putnam, 1983; Ruby *et al.*, 1981), the exact mechanism of their formation has not been adequately described.

The abundance of intraformational shale-clast conglomerates, representing channel margin collapse along the cutbank, and the presence, although rare, of conglomeratic lags are also indicative of a channel setting. Soft sediment deformation structures, such as slump folding, brecciation and small scale gravity faults, are common in the thick accumulations of laterally adjacent shale, marking the position of the channel margin.

Despite this indication of some lateral migration, (i.e. cutbanks), the thick, cohesive accumulations of shale along the channel margins must have impeded erosion. Such migration was, therefore, passive, resulting from intermittent wetting and subsquent slumping of the otherwise cohesive shaly banks. Construction of a paleostructure/paleotopography map, (Fig. 6) using the top of the overlying Lower Colorado Group as a stratigraphic datum, shows no incision into the underlying Sparky formation; the Waseca channel is not, therefore, a valley-fill deposit. Vertical aggradation of channel sands and coeval channel margin shales, rather than vertical stacking resulting from active lateral migration, was the major mechanism for sediment accumulation.

Lithofacies associations and paleontologic constraints demonstrate that the Waseca channel formed in an inland coastal (coastal plain) brackish water environment. The very well sorted nature of the channel sands suggests considerable reworking, and in light of the general environment, tides and waves appear to be the likely mechanisms. This is consistent with observations of oscillation and multidirectional ripples in associated lithofacies, also the result of wave and tidal action.

Towards the south (Golden Lake) the predominance of current formed structures, such as small scale trough cross lamination, current ripple lamination and some high angle planar lamination, in less well sorted and hence less reworked sands, suggest a fluvial origin at least in this part of the study area.

The features described above are incompatible with purely fluvial models. Unlike the Waseca channel, meandering stream deposits are characterized by less well sorted, fining upward sands, occupying an erosional depression. Gravel lags commonly floor the meandering channel. These deposits are typically the result of dynamic lateral migration and as a result, the sands are often vertically stacked. (Collinson, 1978; Allen, 1976). Braided stream deposits are also highly dissimilar to the Waseca channel, in that they are dominantly composed of moderately sorted sands and gravels, with only minor amounts of interchannel fines. Cohesive banks of shale are atypical of braided stream deposits given the high energy conditions necessary for their formation. In addition, this fluvial sequence is typically a valley-fill deposit.

The Waseca channel has been interpreted as an anastomose stream deposit by Putnam (1980, 1983). Certainly, some similarities exist. Anastomose stream deposits are characterized by thick channel sands, accumulated by vertical aggradation; abundant, thick, off-channel fines; and little active lateral migration as a result of bank stability (Smith and Smith, 1980; Putnam, 1980). Nonetheless, major differences also exist between the two. Anastomose channels are characterized by a low width/thickness ratio (narrow, thick

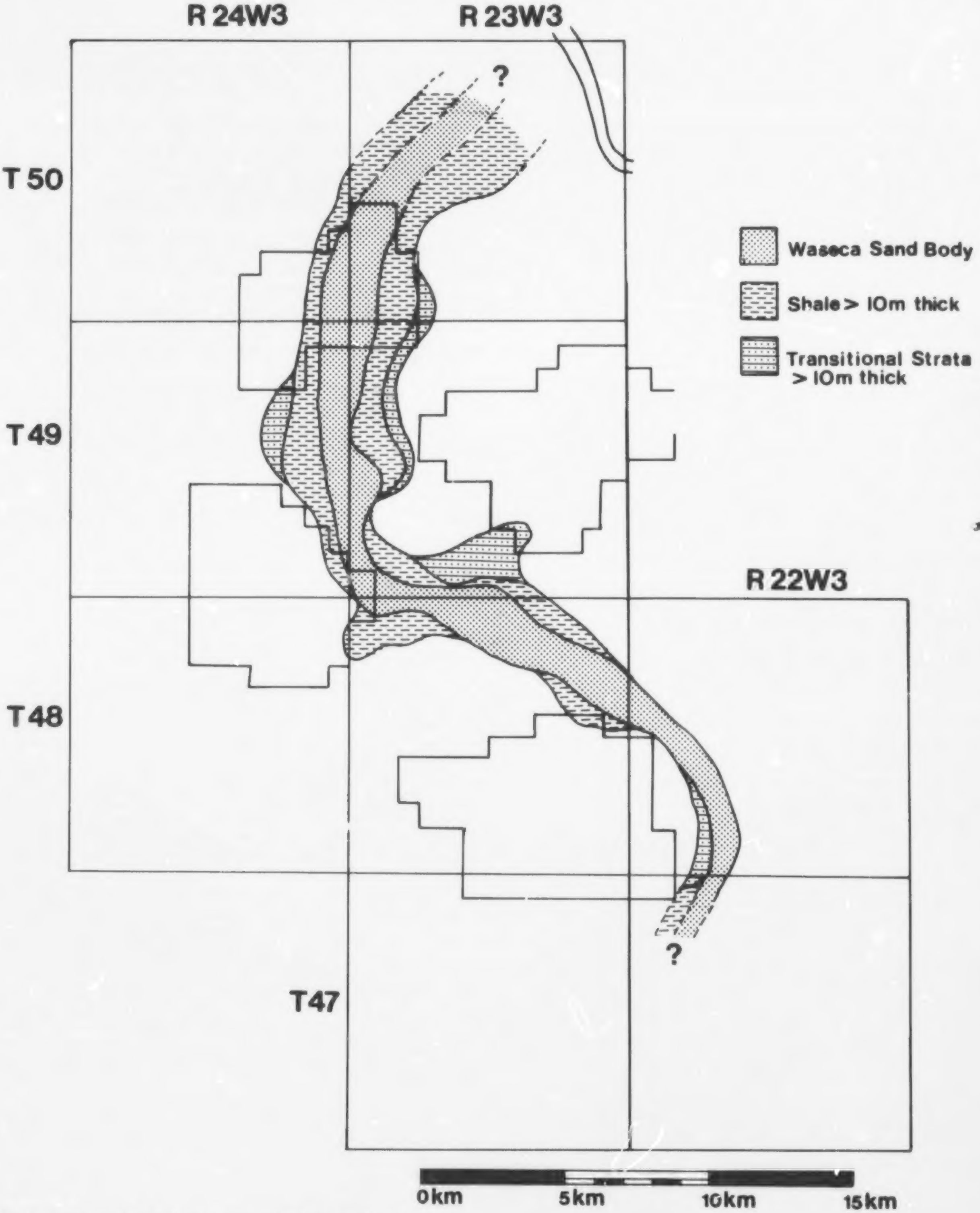
R 24W3
R 23W3
R 22W3
T 50
T 49
T 48
T 47
?
?
Waseca Sand Body
Shale > 10m thick
Transitional Strata > 10m thick
0km
5km
10km
15km

Fig. 4 - Waseca sand body, (after Lorsong and Wilson, unpubl. data, 1981).

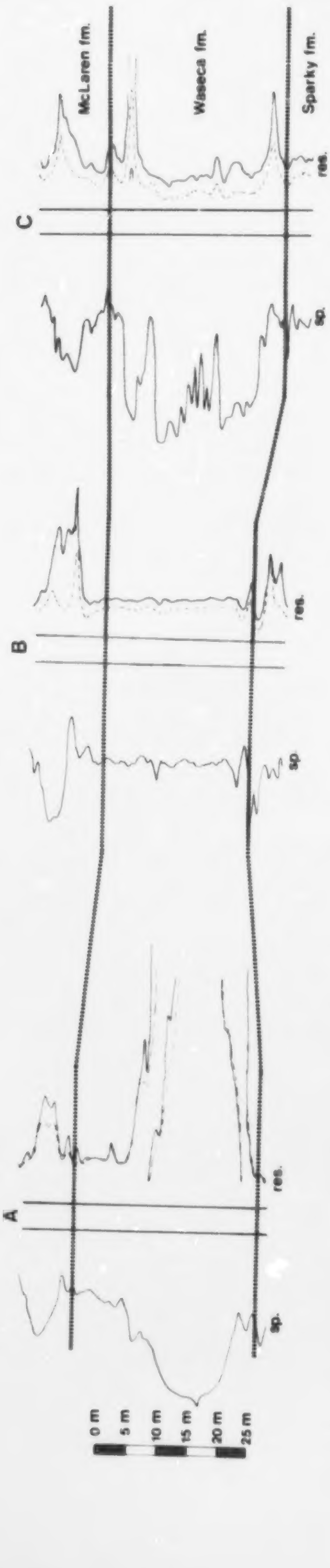

Fig. 5 - Comparison of electric log (spontaneous potential and resistivity) signatures:
A: Waseca Sand Body (Husky Pikes Peak 3B10-1-50-24W3)
B: Laterally Adjacent Shales (Husky Pikes Peak A13-1-50-24W3)
C: "Average" Waseca Signature (Husky Pikes Peak A2-2-50-24W3)

stringers of channel fill) (Smith and Smith, 1980), whereas a cross section of the Waseca channel (Fig. 7) shows it to have a high width/thickness ratio (a sheet-like body). Anastomose channel-fills are predominatly coarse sand and gravel (Smith and Smith, 1980), while the Waseca channel is comprised of reworked, very well sorted fine sand. Anastomose stream systems occupy erosional valleys, unlike the Waseca channel which shows no evidence of incision.

In light of a coastal plain setting demonstrated for the sediments of the study area, supported by coastal settings interpreted for surrounding areas: Celtic Field (Lorsong, 1979, 1980), Tangleflags Field (Wilson, this vol.) and northeastern Lloydminster area (Haidl, 1980); a tidal channel or estuary is envisaged as the setting for the Waseca channel. Evidence for a tidal channel lies chiefly in the deposit's very well elutriated sands which, in a coastal setting, are inferred to be the result of tidal or wave reworking. The dimensions of the deposit, particularly its length of at least 30.2 km, and unidirectional current structures to the south, suggests some fluvial input, indicative of an estuary.

Although most modern estuaries are comprised predominatly of mud and occupy flooded river valleys, (Guilcher, 1967; Rusnack, 1967), this seems to be the result of recent deglaciation and subsequent sea level rise. It is reasonable to expect that the ancient environment hosted sandy estuaries, which, in the upstream direction, would retain fluvial characteristics and in a downstream direction, would acquire tidal channel characteristics.

CONCLUSIONS:

1. Eight lithofacies based on lithology and sedimentary structure have been identified.
2. Paleontologic studies indicate a brackish water setting for the sediments. The presence of syneresis cracks indicating salinity changes reinforces this conclusion. The general environment, based on lithofacies and paleontology, is interpreted as an inland, coastal plain environment.
3. The Waseca sand body, a 0.8-2.7 km wide, 30.2km long, north-south trending, laterally shale bound sand deposit, represents a paleochannel. This conclusion is based on the "shoestring" geometry, the presence of channel margin collapse conglomerates and channel lag gravels (although rare) derived from slumping of coeval shale margins.
4. Cohesive shale margins largely impeded lateral migration, resulting in sand accumulation by vertical aggradation. The underlying formation shows no indication of incisement, demonstrating that the sand body is not a valley-fill deposit.
5. The Waseca channel does not conform to meandering stream, braided stream or anastomose stream models, as outlined by a number of researchers (cf. Allen, 1976; Collinson, 1978; Putnam, 1980; Smith and Smith, 1980). Association with coastal plain sediments and evidence of wave and tidal reworking are supportive of a tidal or estuarine channel environment. Channel dimensions, particularly its length of 30.2 km, and unidirectional current features in the south part of the area suggest some fluvial input was experienced, supportive of an estuarine setting.
6. Although modern estuaries are much muddier than the Waseca channel, this is viewed to be a function of recent deglaciation which has resulted in sea level rise and subsequent drowning of river valleys. Such a situation is considered anomalous in geological history.

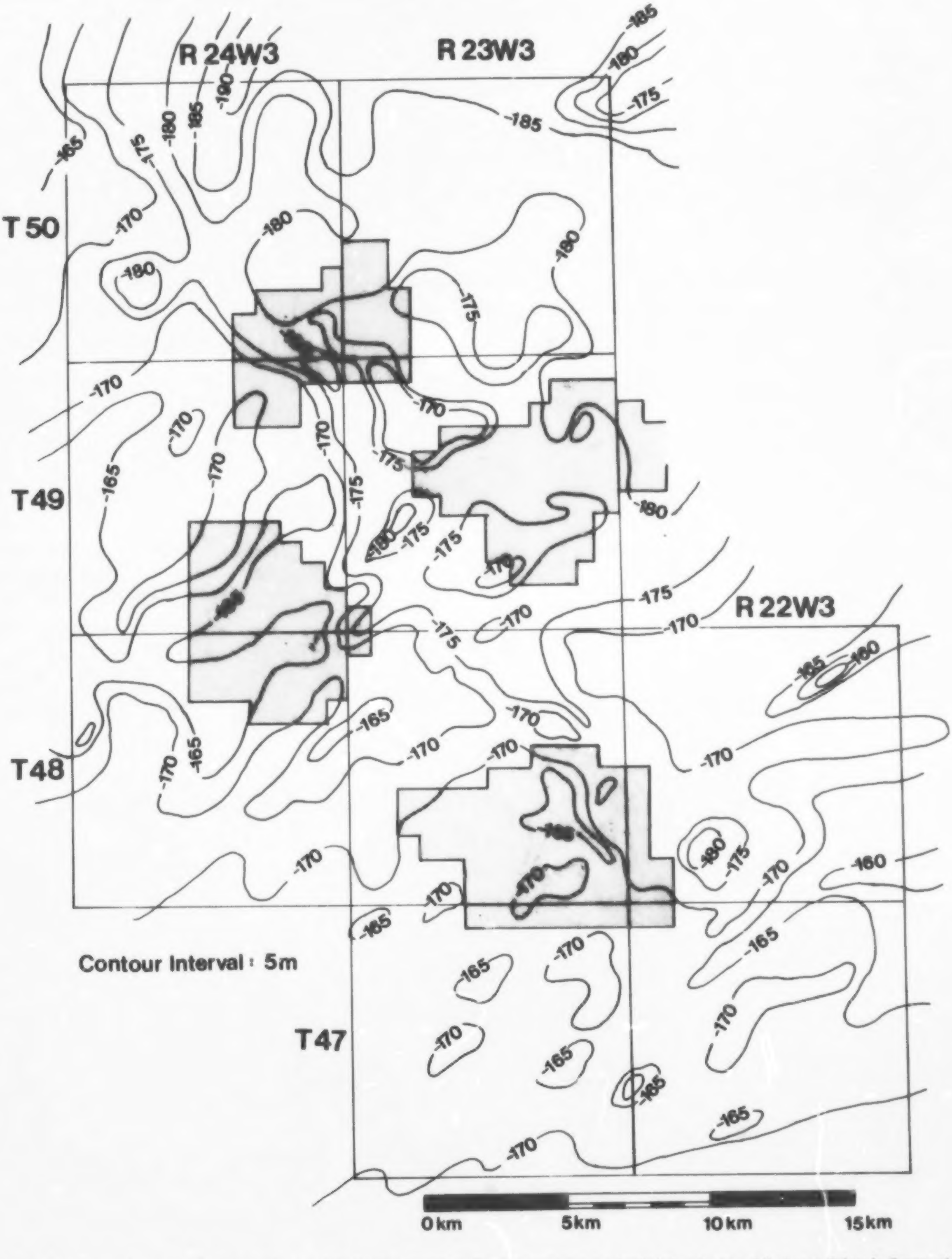
R 24W3
R 23W3
R 22W3
T 50
T 49
T 48
T 47
-165
-170
-175
-180
-185
-190
-160
Contour Interval : 5m
0km
5km
10km
15km

Fig. 6 - Paleostructure/paleotopography map on the top of the Sparky Formation. The contours represent depths below the top of the Lower Colorado Group, which serves as the stratigraphic datum. This is an attempt to eliminate, as far as possible, post-Mannville structure produced by salt solution collapse and to define a basal Waseca depositional surface.

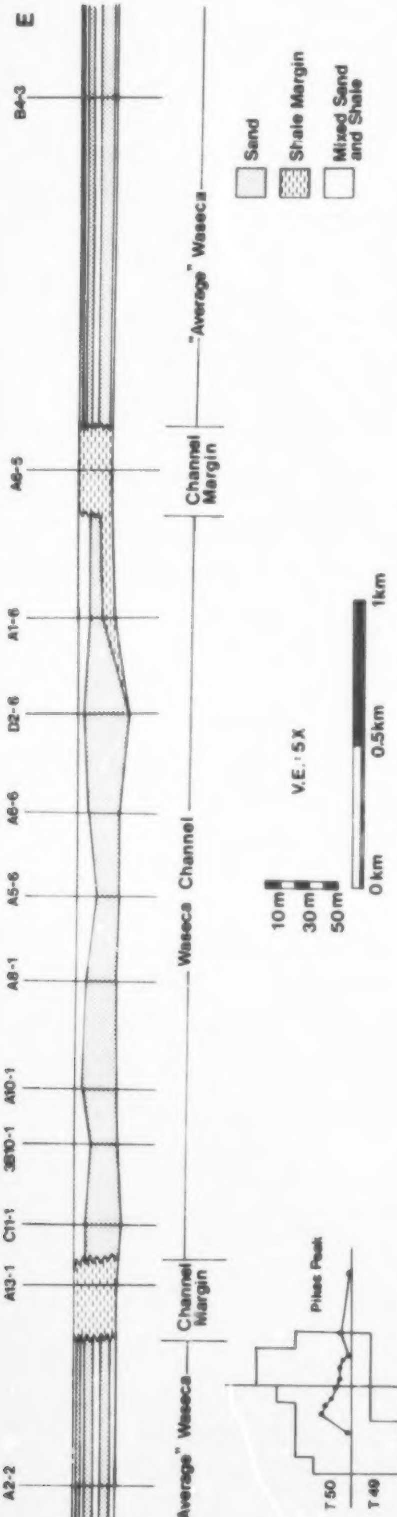

Fig. 7 - Cross-section of the Waseca channel and laterally adjacent shale margins within the "average" Waseca sequence. The top of the Waseca formation is the datum. The basal contact is the top of the Sparky formation.

ACKNOWLEDGEMENTS

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CONTROLS ON HYDROCARBON DISTRIBUTION IN THE MANNVILLE GROUP, NORTHEASTERN LLOYDMINSTER AREA, SASKATCHEWAN

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ABSTRACT

The majority of economic hydrocarbon accumulations in the recently developed northeastern Lloydminster area (Townships 50-52, Ranges 22W3 and 23W3) occur in the G. P., Sparky and Waseca formation of the Lower Cretaceous Mannville Group. Abundant tabular sand bodies (generally less than 7 m thick) exhibit good reservoir properties. Micropaleontological data, sedimentary structures and lithofacies relationships indicate that such sand bodies were deposited in a wave dominated coastal environment characterized by shallow, brackish waters and low depositional gradients. Anomalously thick (up to 32 m) sands with excellent reservoir characteristics are intimately associated with the relatively thin, tabular sand bodies. The thick sands were deposited in large, vertically aggrading channels. Common lateral and vertical facies transitions from unconsolidated sands to less permeable strata create complex reservoir geometries. Sporadic cementation of sands by authigenic clay and/or calcite further complicates the spatial distribution of reservoir strata. Most structures in the study area result from dissolution of Devonian salt in the Prairie Evaporite, primarily after deposition of the Second White Speckled Shale. Gentle, southwesterly regional dips are interrupted by a deep, narrow salt solution trough, creating an asymmetric northwest trending ridge. Most of the hydrocarbons in the G. P. - Waseca interval are trapped in structural culminations along the ridge. Volumes of hydrocarbons within individual structures and the detailed distribution of fluids in multiple, commonly independent, reservoirs are controlled by the complex geometries created by depositional and diagenetic processes.

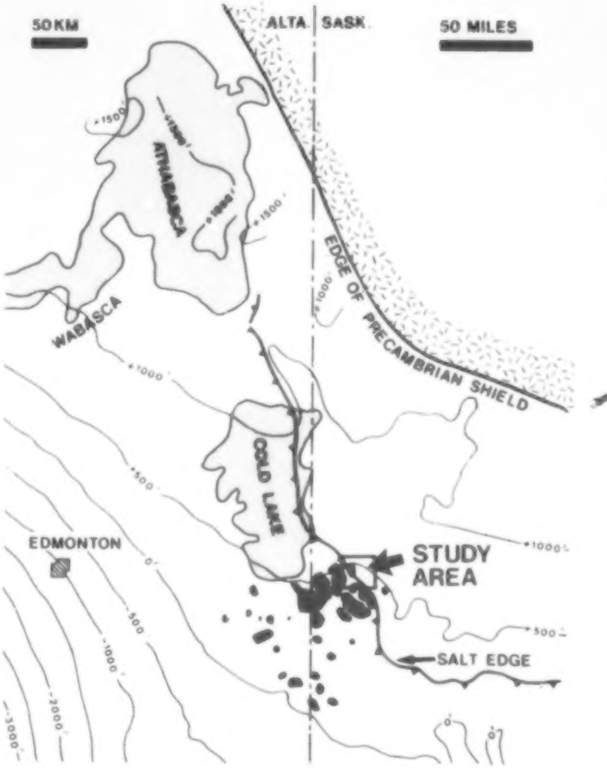


Fig. 1 - Regional structure contours on the top of the Mannville Group illustrate the geometry of the Western Canada Basin in the vicinity of the study area (contour interval is 500 ft.). Lloydminster area heavy oil pools are shown in black; oil sands deposits are shaded in grey. The heavy line with teeth shows the present edge of the contiguous Devonian salt deposits. After Orr *et al.* (1977).

INTRODUCTION

The Lloydminster heavy oil area lies on the northeastern flank of the Western Canada Basin in western Saskatchewan and eastern Alberta (Fig. 1). Vast quantities of oil are trapped in unconsolidated sands of the Lower Cretaceous Mannville Group. Published estimates of original oil in place in the Saskatchewan portion of the area range up to approximately 9.5 billion m^3 (MacCallum and McCrossan, 1979). The Lloydminster area is of increasing economic significance as exploration for conventional reserves becomes more expensive and heavy oil production technology (enhanced recovery) is developed. A detailed understanding of hydrocarbon distribution within Mannville strata is essential to succesful exploration for, and exploitation of the resource.

The purpose of this paper is to elucidate controls on the distribution of fluids in the formations of greatest economic significance in the recently developed northeastern portion of the Lloydminster area. The study area encompasses 570 km^2 in Townships 50 to 52, Ranges 22 and 23 inclusive (Fig. 2). The are includes the Celtic and Westhazel Fields in their entirety as well as portions of others (Pikes Peak, Standard Hill and Tangleflags East). An active exploration program was conducted in the area in the late 1960's with sporadic drilling continuing through the early 1970's. The late 1970's marked a period of intensive drilling, including the initiation of the Mobil Celtic pilot project. Activity has been sustained with several major discoveries and delineation of extensive reserves. Exploration and development drilling is ongoing, with approximately 20 wells drilled in the area in the first half of 1984.

The study area currently includes approximately 400 wells, of which about 100 are cored. For this study, petrophysical logs from 385 wells and cores from 60 wells were examined. Petrophysical logs from all wells except those in the Celtic enhanced recovery pilot project (Section 10, Township 52, Range 23W3) have been analysed in detail. Wherever available, at least one core in each section has been examined.

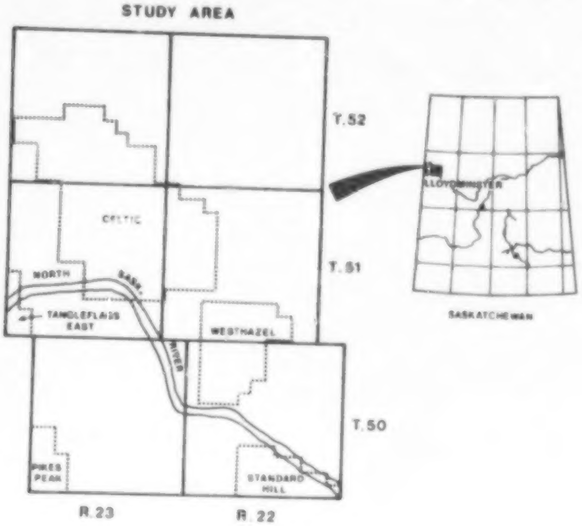

STUDY AREA
T.52
T.51
T.50
R.23
R.22
CELTIC
NORTH
SASK.
RIVER
TANGLEFLAGS EAST
WESTHAZEL
PIKES PEAK
STANDARD HILL
LLOYDMINSTER
SASKATCHEWAN

Fig. 2 - Location map shows the boundaries of the oil fields in the study area.

STRATIGRAPHY

The Lower Cretaceous Mannville Group comprises a complex sequence of unconsolidated sands, silts, shales, and minor coals averaging about 200 m thickness in this area. In the study area, the Mannville lies unconformably on Upper Devonian carbonates of the Duperow Formation (Christopher, 1980, Fig. 3). Mannville strata are overlain, probably disconformably, by marine shales of the Joli Fou Formation (Wickenden, 1948) (Fig. 3).

In the Lloydminster region no formal stratigraphic units have been recognized within the Mannville. Current nomenclature has evolved from the terms defined by Nauss (1945) and Wickenden (1948) as well as from drillers' terminolgy (Edmunds, 1948; Kent, 1959; Fuglem, 1970). In present usage, the Mannville is divided into nine informal units based on lithological variations defined by petrophysical log characteristics (Vigrass, 1977; Orr *et al.*, 1977). Repetition of similar lithologies throughout the Mannville and the absence of widespread marker beds result in correlations based largely upon the position of a given unit in the vertical sequence; this is particularly true of anomalously thick sand or shale sequences (Haidl, 1980).

The informal stratigraphic scheme employed here (Fig. 4) is adopted from Vigrass (1977), with the exception that the top of the Sparky is defined to be the top of the coal or an equivalent stratum. The nine informal units are considered to be formations, in accordance with previous usage (Lorsong, 1980b).

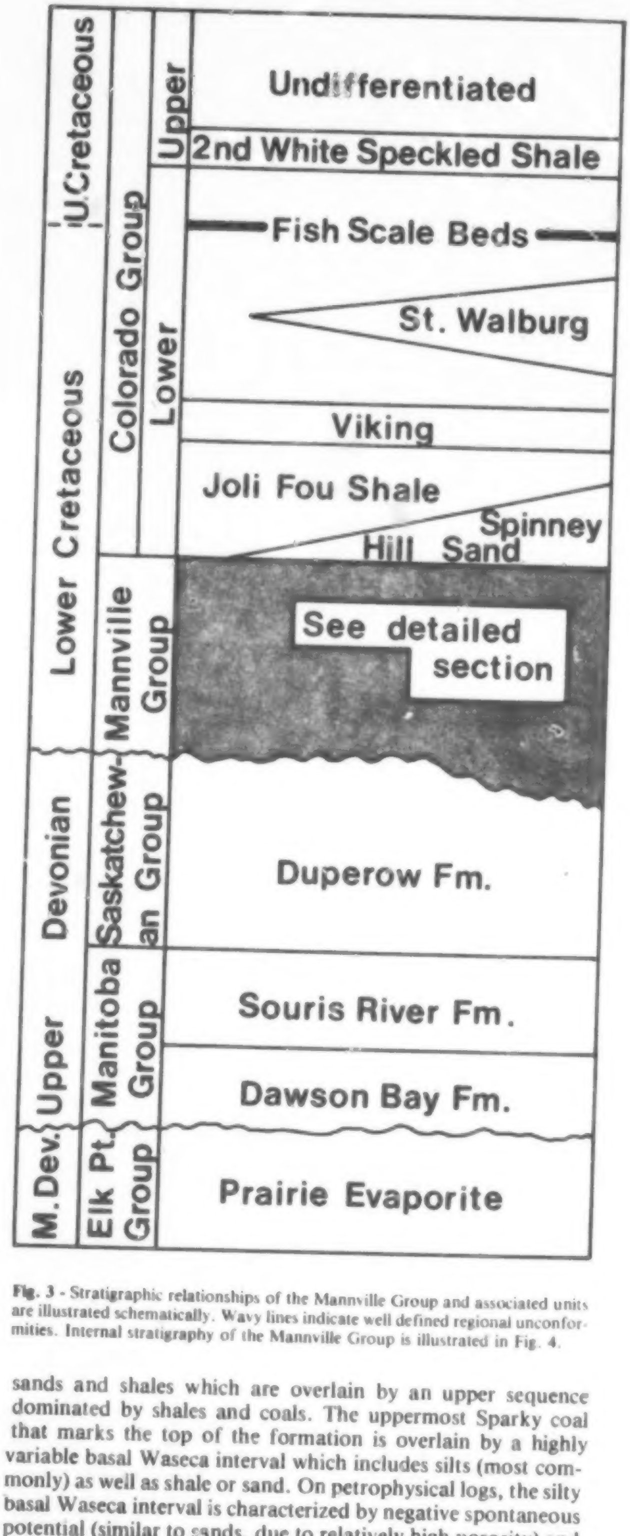

U.Cretaceous
Lower Cretaceous
Devonian
Upper
M.Dev.
Colorado Group
Upper
Lower
Mannville Group
Saskatchewan Group
Manitoba Group
Elk Pt. Group
Undifferentiated
2nd White Speckled Shale
Fish Scale Beds
St. Walburg
Viking
Joli Fou Shale
Spinney Hill Sand
See detailed section
Duperow Fm.
Souris River Fm.
Dawson Bay Fm.
Prairie Evaporite

Fig. 3 - Stratigraphic relationships of the Mannville Group and associated units are illustrated schematically. Wavy lines indicate well defined regional unconformities. Internal stratigraphy of the Mannville Group is illustrated in Fig. 4.

The formations considered in detail are the General Petroleums (G. P.), Sparky and Waseca (Fig. 4). These contain most of the oil in the study area; stratigraphically lower formations are generally water saturated and higher formations are characterised by poor reservoir quality and natural gas accumulations. The G.P. typically comprises a basal shale followed by a sandy sequence; it is underlain by the sands of the Rex formation. The G. P. is overlain by the basal shaly interval of the Sparky formation. The middle portion of the Sparky generally consists of sands as well as thinly interbedded sands and shales which are overlain by an upper sequence dominated by shales and coals. The uppermost Sparky coal that marks the top of the formation is overlain by a highly variable basal Waseca interval which includes silts (most commonly) as well as shale or sand. On petrophysical logs, the silty basal Waseca interval is characterized by negative spontaneous potential (similar to sands, due to relatively high porosity) and high gamma ray counts (similar to shales, due to relatively high feldspar content). The basal Waseca commonly contains zones

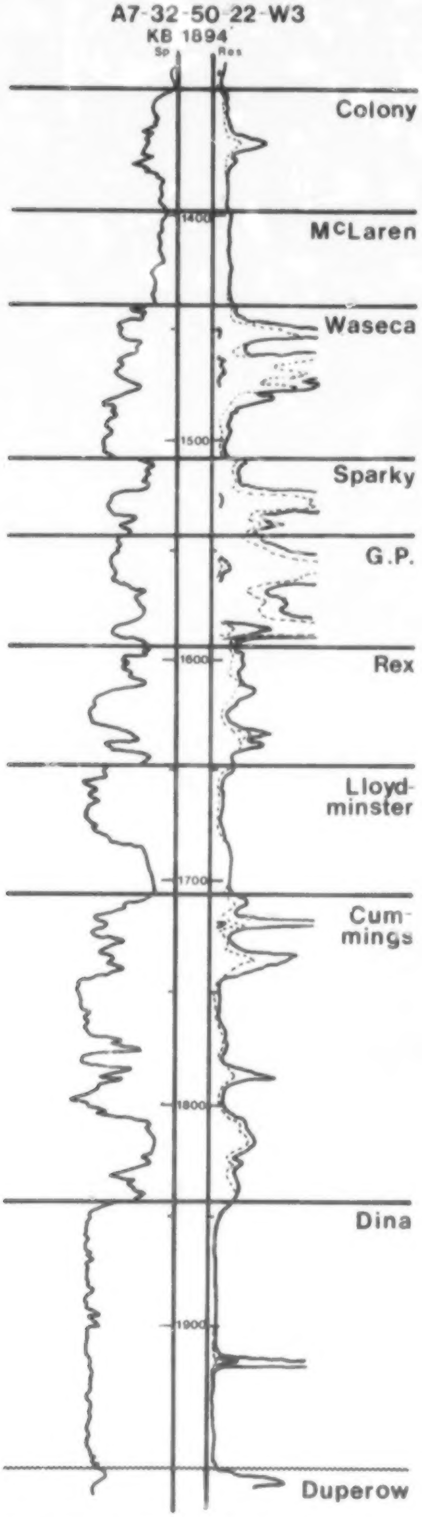


Fig. 4 - The Mannville Group is informally divided into the nine formations illustrated. The formations are defined by log character and stratigraphic position. Depths are in feet.

cemented by calcite and clay. The bulk of the Waseca consists of sands separated by thinly interbedded sands and shales. The top of the Waseca is defined by transition to a relatively thick shale or shaly interval that comprises the base of the McLaren formation.

SEDIMENTOLOGY

There is abundant evidence that the G.P., Sparky and Waseca formations accumulated in a coastal environment in the Lloydminster area (*e.g.*, Lorsong, 1979, 1980a; Smith *et al.*, this volume; Wilson, M. A., this volume; MacEachern, this volume). This environment is characterized by shallow brackish water, low depositional gradients and domination by wave processes (Lorsong and Haidl, 1982).

The sediments of the G.P.-Waseca interval can be conveniently described in terms of eight lithofacies encompassing common variations in sedimentary structures and grain size observed in cores (Lorsong, 1979). The salient characteristics of each lithofacies (Facies in the text) are summarized in Table 1. It is emphasized that the lithofacies scheme is descriptive and general in nature: interpretation of individual cores depends upon the precise character and sequences of structures and textures (Lorsong, 1979). Cored intervals are illustrated here with the lithofacies scheme (Figs. 12, 16).

SAND BODY GEOMETRY

Most Mannville sand bodies are relatively thin, (usually less than 7 m thick) and are characterized by a relatively large areal extent. Generally, such sands are either wave generated or associated with wave dominated deposits (*cf.* Lorsong, 1980b). The well-defined upper limit of thickness of thin sands reflects

Lithofacies	Lithology	Typical Structures
L	sand	low angle ($<15°$) planar cross lamination and horizontal planar lamination
T	sand-silt	other types of cross lamination; commonly includes oscillation ripples
M	sand-silt	structureless
R	conglomerate or breccia	typically with structureless sand matrix
B	sand and shale	thin (<20 cm) interbeds, commonly lenticular to flaser bedded and bioturbated
S_1	shale-silt	structureless or intensely bioturbated
S_2	shale and silt	shale with silt laminae or lenses
C	coal/very carbonaceous shale	typically structureless

Table 1 - Lithofacies scheme (after Lorsong, 1979, pers. comm., 1984).

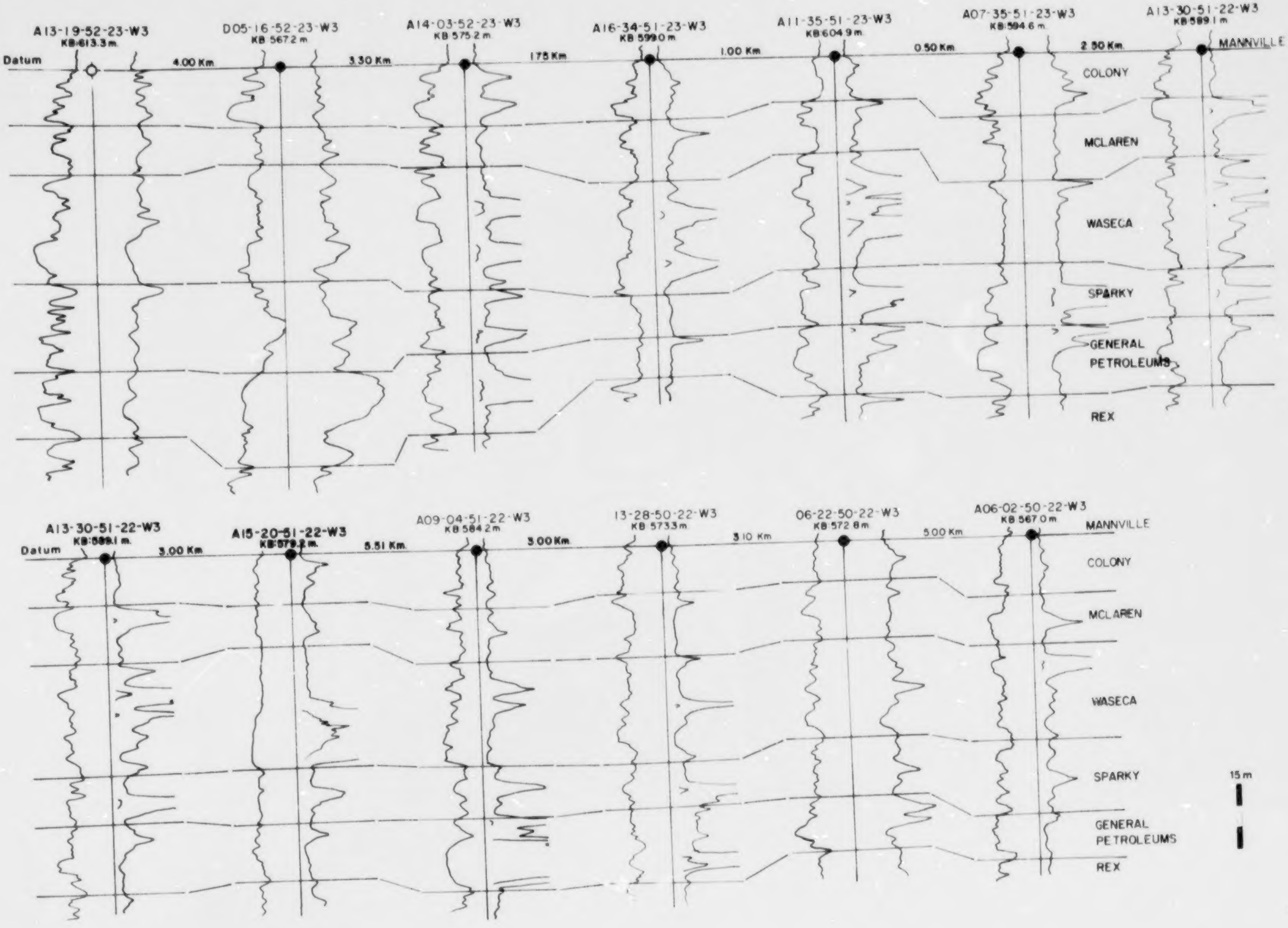

A13-19-52-23-W3
KB:613.3 m
D05-16-52-23-W3
KB 567.2 m
A14-03-52-23-W3
KB 575.2 m
A16-34-51-23-W3
KB 599.0 m
A11-35-51-23-W3
KB 604.9 m
A07-35-51-23-W3
KB 594.6 m
A13-30-51-22-W3
KB 589.1 m
Datum
4.00 Km
3.30 Km
1.75 Km
1.00 Km
0.50 Km
2.50 Km
MANNVILLE
COLONY
MCLAREN
WASECA
SPARKY
GENERAL
PETROLEUMS
REX
A13-30-51-22-W3
KB:589.1 m
A15-20-51-22-W3
KB:579.2 m
A09-04-51-22-W3
KB 584.2 m
13-28-50-22-W3
KB 573.3 m
06-22-50-22-W3
KB 572.8 m
A06-02-50-22-W3
KB 567.0 m
Datum
3.00 Km
5.51 Km
3.00 Km
3.10 Km
5.00 Km
MANNVILLE
COLONY
MCLAREN
WASECA
SPARKY
GENERAL
PETROLEUMS
REX
15 m

Fig. 5 - Northwest-southeast regional stratigraphic cross-section (spontaneous potential and resistivity logs) illustrates lithological variations across the study area, including a calcite cemented Sparky sand (D5-16), a Waseca "shale-out" (A7-35), a Waseca channel sand (A15-20) and a G. P. channel sand (A9-4). Location of the section is shown in Fig. 7.

some depositional hydrodynamic control, such as water depth (Lorsong and Haidl, 1982).

Sand bodies greater than 7 m thick are defined as anomalous sands and are relatively common in the study area. Anomalous sands are present in the G.P. in the Westhazel area (A9-4-51-22W3, Fig. 5; Figs. 11, 12) and the Sparky-G.P. in the Celtic area (5-16-52-23W3, Fig. 5). Thick sands (up to 32 m thick) also occur in the Waseca of the Pikes Peak (Fig. 6), Englishman Lake (A15-20-51-22W3, Fig. 5; Figs. 6, 14) and Spruce Lake (16-35-52-22W3;/Fig. 6) areas.

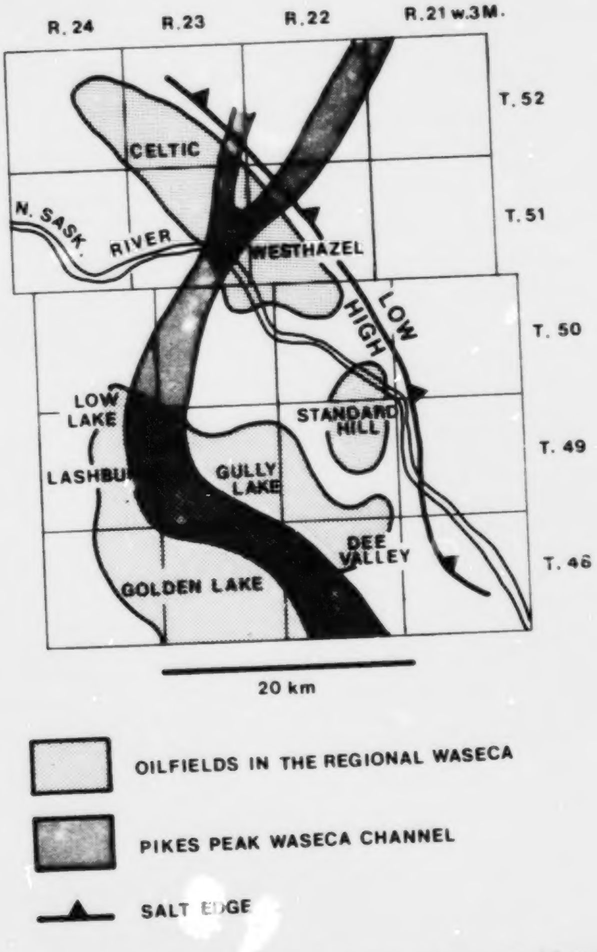


Fig. 6 - Outline of the Pikes Peak channel which extends northeastward through the study area. After van Hulten (in press).

In core, anomalously thick sands are characterized by several distinctive features. The sands are typically structureless, with or without sporadic high angle planar cross lamination in sets of variable thickness. Angular to subangular shale clasts, up to 50 cm or more in maximum dimension, are common. Shale clasts locally constitute up to 85% of the sediment. Well rounded (uncommonly broken or abraded) Ca,Mg,Fe-carbonate nodules (typically less than 5 cm in diameter) occur in minor proportions. The sands typically overlie "normal" sediments with a sharp, demonstrably erosional, contact.

In general, anomalously thick sands appear as very long, narrow, sinuous bodies in plan view; the cross sectional geometry is tabular. The best documented example of such geometry is the Pikes Peak deposit, which extends more than 30 km (mostly south of the study area) (Lorsong, J. A. and Wilson, M. A., unpublished data, 1981; van Hulten, in press). The Pikes Peak deposit varies from 1 to 2 km wide, with an average thickness/width ratio of about 1:50. All of the Waseca deposits and the west Celtic G.P. body may be bordered by anomalously thick (up to 33 m) shales with abrupt lateral transitions from thick sand to shale (within 200 m where well control is sufficient). Anomalously thick shales also commonly overlie thick sands, everywhere with gradational contacts.

The salient features (especially the large, angular shale clasts) of the anomalously thick sands indicate deposits of channelized flows in a system characterized by rapid vertical aggradation; however, the depositional regimes of such flows are not well understood (Lorsong, J. A., pers. comm., 1980).

The Pikes Peak channel has been interpreted by Putnam (1980, 1982) as a fluvial deposit with drainage to the northwest; MacEachern (1982, this volume) and van Hulten (in press) place it in a tidal/estuarine setting with drainage to the northeast. The proximity of the channel deposit to the regional Waseca coastal sediments supports the inferred coastal setting of the channel deposit. In the Westhazel area, the anomalous sand is in sharp contact with the basal G.P. shale which contains an assemblage of foraminifera indicative of restricted marine conditions (Atkin, K. T. J., pers. comm., 1984). This suggests progradation of the channel system over subtidal deposits.

DEPOSITIONAL HISTORY

The G.P.-Sparky and the Waseca-Colony intervals apparently represent two transgressive events that can be recognized throughout the study area. This inference is suggested by sedimentological data (Lorsong, J. A., pers. comm., 1982) and micropaleontology (Atkin, K. T. J., pers. comm., 1984). The two sequences recognized here do not necessarily represent the only isostatic sea level changes recorded in the G.P.-Waseca interval. They are, however, relatively easily recognised, and the model provides the framework for interpretation of the G.P.-Waseca sequence, which is, in turn, a key to understanding the spatial distribution of hydrocarbon reservoirs in the area.

General Petroleums Formation

A few cores of the upper Rex formation (e.g., 11-3-51-22W3) suggest that sands containing marine trace fossils (*cf. Teichichnus*) and overlying a coal bed represent the deposits of a marine transgression. Marine conditions prevailed during deposition of the basal G.P. shale, as evidenced by dinoflagellates and assemblages of foraminifera including *Ammomarginulina* sp., *Ammobaculoides* sp., *Miliammina* sp. and *Gaudryina* sp. in the Westhazel and Celtic areas (Atkin, K. T. J., pers. comm., 1984; P. Sherrington and J. Utting, pers. comm., 1980). The basal shale extends throughout the study area.

Depositional regimes were highly variable in the upper G.P. throughout the study area. In the east central Celtic area, the upper part of the formation consists predominantly of wave generated sand bodies (Facies L) (*cf.* Lorsong, 1980b). In the Westhazel and west Celtic areas, channel deposits, possibly of tidal origin, are present. In the Standard Hill area, the G.P. consists of a wide range of lithologies including clean sands and cemented sands, as well as thick shales (greater than 10 m) and coals (up to 3 m) which suggst dominance of intertidal to supratidal conditions.

Sparky Formation

The lower portion of the Sparky formation comprises laminated shales (Facies S_2) and/or thinly interbedded sand and shale (Facies B). Lithologies vary considerably; the presence of pinstripe lamination and the stratigraphic position of the strata suggest dominantly intertidal deposition. This contrasts with the apparently marine strata at the base of the Sparky in the Aberfeldy Field (Smith *et al.*, this volume; Fuglem, 1970; micropaleontology by Sherrington, P. and Utting, J., 1980).

The middle sandy portion of the Sparky comprises various ripple cross laminated sands with some evidence of larger sinuous crested bedforms (dunes) (Facies T), Facies M and Facies L sands, and thinly interbedded sand and shale (Facies B). The sands are commonly cemented by clay and may contain root traces, particularly toward the top of the sequence. These strata are interpreted to represent intertidal deposition with some development of paleosols (cemented and rooted sands).

The upper Sparky consists predominantly of shales (Facies S_1 and S_2) and coals with abundant plant debris and root traces. These lithologies clearly represent high intertidal and supratidal deposition.

Waseca Formation

With the exception of the Pikes Peak-Spruce Lake channel deposit (Fig. 6), Waseca sedimentation in the study area is characterized by a series of coarsening upward sequences. The basal unit consists primarily of shales and silts which commonly contain clay and/or calcite cemented zones. The other coarsening upward sequences consist mainly of sands dominated by low angle planar lamination (Facies L) commonly interbedded with Facies B. In general, the proportion of sand and the occurrence of wave generated structures decreases toward the southeast (Fig. 5).

Renewed marine influence during Waseca deposition is indicated by the abundance of wave generated structures in the Waseca, particularly in the Celtic area (Lorsong, 1980a,b). Micropaleontological samples from three locations in the study area yielded no identifiable foraminifera; one sample contained abundant fish debris (Atkin, K. T. J., pers. comm., 1984; Sherrington, P. and J. Utting, pers. comm., 1980). Preliminary micropaleontological data from an adjoining area suggest, however, a Waseca transgression (Atkin, K. T. J., pers. comm., 1984). Sedimentary structures and paleontological data from the Waseca formation suggest subtidal deposition above fair weather wave base.

STRUCTURE

The structure of Mannville strata in the study area is illustrated by contours on the top of the Waseca formation (Fig. 7). Structure contours on the other stratigraphic horizons of interest (*e.g.*, tops of the Sparky and G.P. formations) are not illustrated; however, they display patterns very similar to that shown by the top of the Waseca.

In the vicinity of the study area, Mannville strata dip gently (approximately 1:750) to the southwest, toward the centre of the Western Canada Basin (Fig. 1). The regional dip is disrupted by a deep, narrow, linear trough which trends northwest through the study area (Fig. 7). Strata dip relatively steeply into the trough at the southwestern margin and rise relatively gently from the trough axis to the northeast, forming an essentially homoclinal structure. The dip reversal at the southwestern margin of the trough forms a narrow belt (less than 2 km wide), with dips commonly exceeding 1:50 and up to 1:25 east of the Standard Hill Field. Dips at the opposite margin of the trough are much more gentle (about 1:250), but steeper than the regional dips.

The regional southwesterly dip and the belt of dip reversal combine to create a prominent ridge along the southwestern margin of the trough. The ridge is transected by a series of narrow lows of minor relief which create a series of closed structural highs bordering the trough (Fig. 7). The axis of the ridge plunges gently (approximately 1:750) to the southeast, such that the elevation of the culmination of each structure is progessively lower to the southeast.

Southwest of the ridge, Mannville strata dip relatively uniformly toward the Pikes Peak Field, where a closed structural high is encountered (Fig. 7). This high is part of a second anticlinal structure which trends through the Tangleflags Field, parallel to the ridge bordering the trough (van Hulten, in press; Wilson, M. A., this volume).

The regional southwesterly dip in the Lloydminster area is probably associated with the Laramide orogeny (Christopher, 1980). The complex assemblage of lows and highs which characterize Mannville structure are largely attributable to the tectonics associated with dissolution of Devonian salts of the Prairie Evaporite (Orr *et al.*, 1977; Christopher, 1980). The prominent northwest trending trough is a regional feature which coincides with the present edge of contiguous Prairie Evaporite salt deposits (Fig. 1; van Hulten, in press, Fig. 3A). The narrow, linear geometry of the trough and coincidence with the salt edge indicate that it is a collapse structure created by salt dissolution.

Dissolution of the Prairie Evaporite in Saskatchewan has proceeded episodically for a long span of time. Dissolution probably commenced in the Late Devonian; a significant phase of activity is inferred for the Early Cretaceous (Christopher *et al.*, 1971). Substantial dissolution of salt during Mannville deposition is evident in the general vicinity of the study area. An isopach map of the interval from the Cretaceous/Devonian unconformity surface to the base of the Fish Scale Zone shows a thickening northeast into the salt dissolution trough, suggesting that subsidence induced by salt dissolution was active in that area during Mannville deposition (van Hulten, in press, Fig. 3A). In the Edam area (Township 47-51, Range 18-21W3), salt dissolution is inferred to have occurred in four discrete phases, probably beginning in Late Devonian time. Two phases occurred in the Mannville during deposition of the basal Mannville sequence and the Sparky-G.P. interval. The most important phase of dissolution postdates deposition of the Second White Speckled Shale (Wilmot, B., pers. comm., 1984).

Within the G.P.-Waseca interval, there is no evidence of anomalous thickening to suggest active salt dissolution during deposition in most of the study area. A thickened G.P.-Sparky interval in Township 50, Range 23W3 may represent an area of local subsidence during deposition (Fig. 8). Moreover, the inferred extension of the Pikes Peak channel across the salt dissolution trough into the Spruce Lake area (16-35-52-22W3) indicates that the trough was not topographically expressed along that portion of the salt edge during Waseca channel

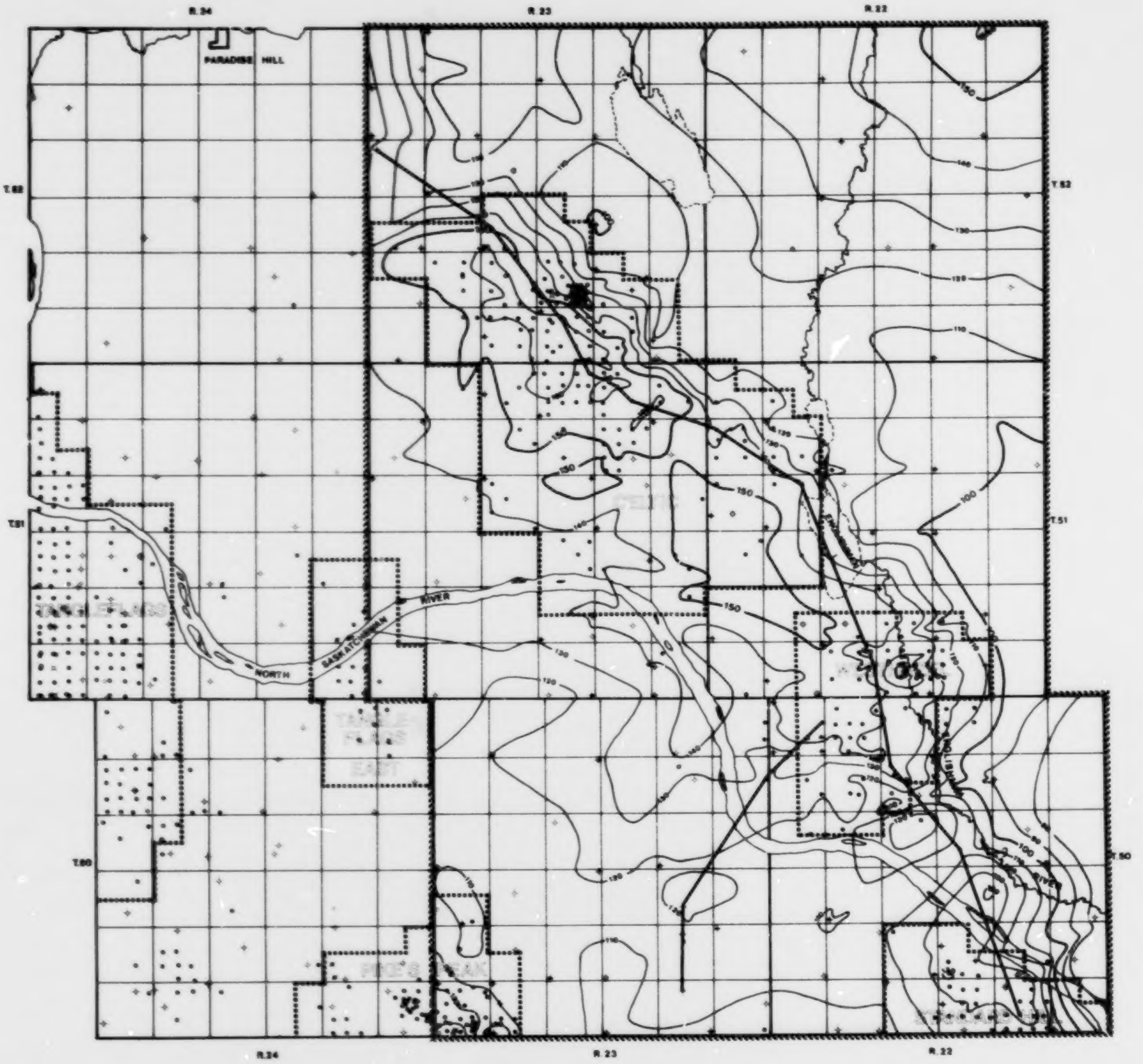


Fig. 7 - Structure contours on the top of the Waseca formation illustrate the major ridge on which the Celtic, Westhazel, and Standard Hill Fields are located. The ridge borders a major salt solution trough to the east. The Pikes Peak Field lies on a second northwest trending high in the southwestern corner of the study area. Heavy solid lines indicate locations of the northwest-southeast regional cross section (Fig. 5) and the southwest-northeast Westhazel section (Fig. 8). The study area is outlined by hachures.

deposition. Structural relief in the trough is subdued in the vicinity of the channel deposit. In part, this may reflect differential compaction; it may also indicate less complete dissolution of salt in that area. Subsidence more recent than Waseca deposition is also evident in the Pikes Peak area: the channel clearly extends northward to 2-18-50-23W3, which is now 30 m lower than the main pool (Fig. 6, 7; van Hulten, in press).

An isopach map from the Waseca formation to the base of the Second White Speckled Shale indicates no significant thickening of strata. It seems likely, therefore, that the major period of salt dissolution in the study area is more recent than the Second White Speckled Shale.

CONTROLS ON HYDROCARBON DISTRIBUTION

OIL

The distribution of oil in the G.P.-Waseca interval in the study area is illustrated by net pay maps (Figs. 9, 10, 13, 15). Net pay is the aggregate thickness of reservoir strata of sufficient quality and oil saturation to produce, oil here net pay is aggregated by formation. Producible strata are defined by the

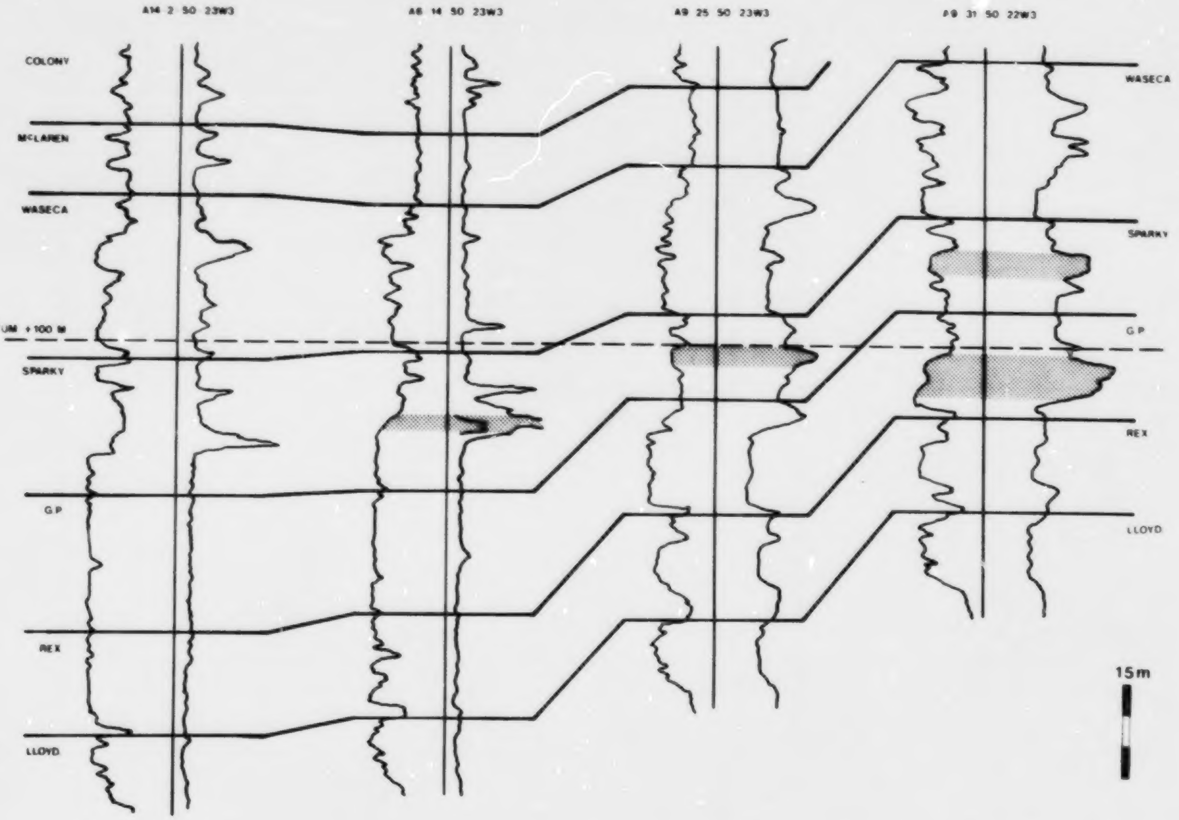


Fig. 8 - Southwest-northeast structural cross section (spontaneous potential and resistivity logs) illustrates fluid distribution in the G. P. and Sparky formations southwest of the Westhazel Field; oil is shaded in grey. The G. P. Sparky interval thickens in southwesterly direction.

following typical petrophysical log criteria: 1) deep resistivity greater than 8 ohm/m; 2) well defined negative (sand) spontaneous potential response; 3) well defined low (sand) gamma ray count; and 4) density porosity greater than 27%. Correlation of cores and petrophysical logs indicates that these are the minimum values which reliably define oil reservoirs but lesser values do not preclude the presence of oil. Thin (generally less than 0.5 m) or highly argillaceous oil saturated sands do not produce a characteristic log response and therefore cannot be mapped (*cf.* Haidl, 1980).

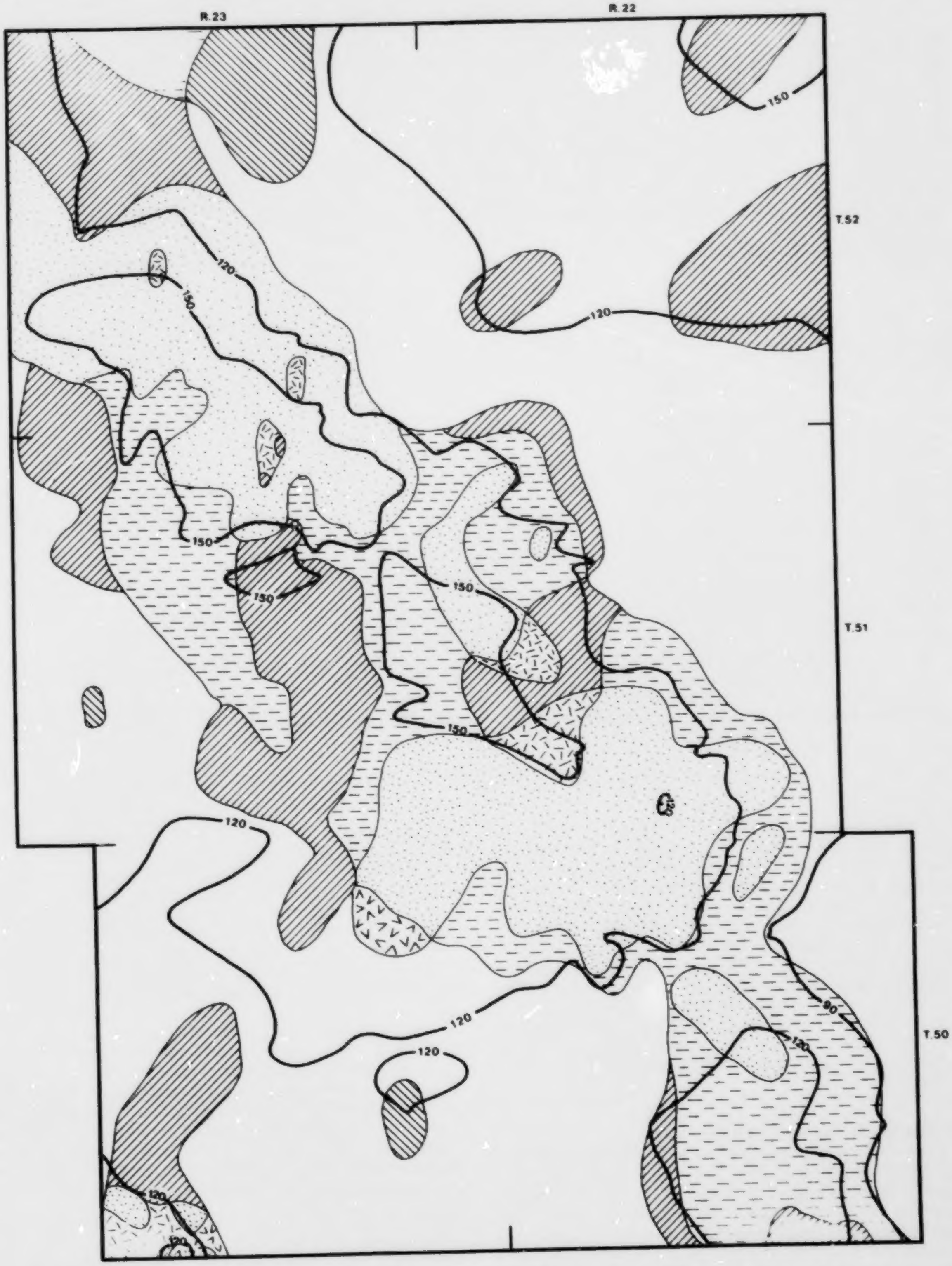
The occurrence of oil in the study area is controlled primarily by structural relief and by distribution of lithologies. The major areas of oil entrapment are structural highs created by local subsidence due to salt solution (see above). The volume of oil trapped in the structures and the complex geometry of specific pools is largely determined by the spatial distribution of porous and permeable reservoir sands.

The major oil accumulations occur in a series of closed structural highs along the ridge parallel to the salt solution trough (Fig. 9). The coincidence of zero net pay contours with the general trend of structure contours on the top of the Waseca, particularly near the trough, demonstrates structural control on the distribution of oil. Structural control is also reflected in variations of net pay associated with local lows which transect the ridge (*e.g.*, G.P. formation in the Westhazel area; Figs. 9, 11) and in subsidiary oil occurrences on highs in the Pikes Peak and Spruce Lake areas. The Spruce Lake occurrence is also significant in that it demonstrates that oil migrated farther east than the salt solution trough.

The relationship between structure and oil distribution is complicated by irregular, inclined oil/water contacts. Oil/water contacts within reservoir sands along the western edge of the ridge are consistently at higher elevations than those bordering the trough; this is reflected in the dispositions of zero net pay contours (Fig. 9). The cause(s) of this phenomenom is not well understood. A potentiometric surface may slope into the trough. It is also possible that several oil lenses may be in an unstable gravity segregation phase related to structural movement more recent than oil migration. The period of time since deformation may be insufficient for equilibration of high viscosity (greater than approximately 5,000 mPa.s at reservoir temperature) oils now in structural lows (*cf.* Wennekers *et al.*, 1979; van Hulten, in press).

The lithological variation within the G.P.-Waseca interval also controls the distribution of oil. Mannville sediments are

Fig. 9 - Composite net pay map illustrates the distribution of oil in the G. P., Sparky, and Waseca formations and the relationship to structure. Areal distributions of oil in each formation or combination of formations are shown by various patterns. Structure contours are on the top of the Waseca formation (contour interval is 30 m); detailed structure is shown in Fig. 7. Detailed net pay maps of local areas are shown in Figs. 10, 13, and 15.


R.23
R.22
T.52
T.51
T.50
150
120
150
120
150
150
150
150
150
120
120
120
90
120
120
120
WASECA
SPARKY
WASECA AND SPARKY
WASECA AND G.P.
SPARKY AND G.P.
WASECA, SPARKY AND G.P.

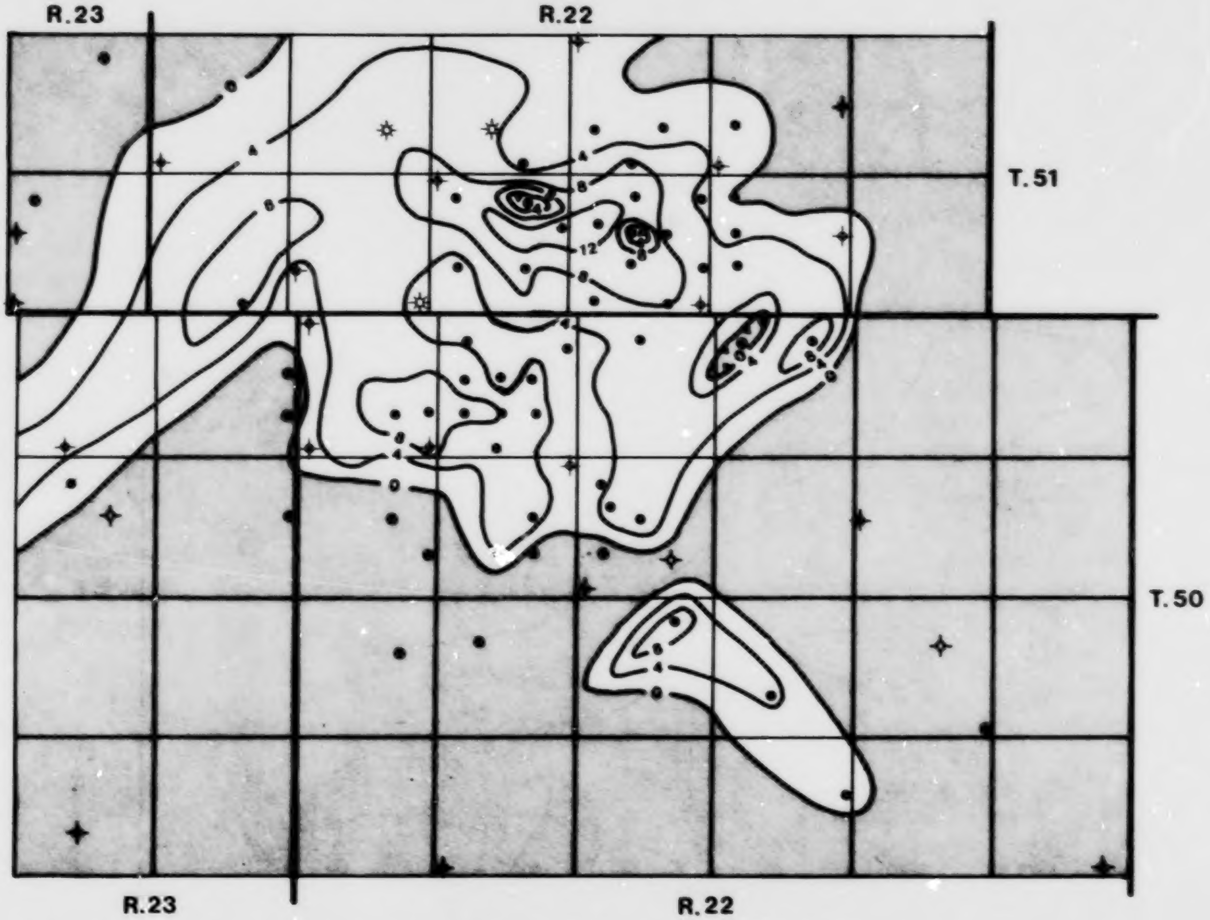


Fig. 10 - Isopach map of net oil pay illustrates the distribution of oil within the G. P. formation in the Westhazel area (contour interval is 4 m).

characterized by abundant sand bodies with excellent reservoir properties. Common vertical facies changes to less permeable strata result in multiple, vertically stacked, dynamically independent reservoirs. Reservoir seals may also be created or enhanced by diagenesis (Lorsong, 1981). Lateral permeability variations reflecting primarily depositional facies changes, and to a lesser extent diagenesis, commonly result in local reductions of net pay (*e.g.*, Figs. 5, 10, 13, 15). Zones of significantly reduced permeability also act as barriers to lateral oil migration, particularly on flanks of structural highs (*e.g.*, the Waseca formation in the Spruce Lake area). The following discussions of oil distribution in specific areas provide detailed illustrations of structural and stratigraphic trapping mechanisms.

G.P. FORMATION, WESTHAZEL AREA

Variations in the thickness and quality of reservoir sands are important determinants of fluid distribution in the G.P. formation in the Westhazel area (Figs. 10, 11, 12). The main reservoir is a channel sand that lies immediately above the basal G.P. shale. In the Field itself, the sand is a maximum of 13 m thick with 3 to 12 m of net pay (A12-3-51-22W3, Fig. 11). To the southwest, the channel sand is apparently part of a thick sequence of vertically contiguous sands(s) in the Rex, G.P. and Sparky formations (Fig. 8). The reservoir is thinner and/or more argillaceous near the centre of the deposit (*e.g.*, 13-32-50-22W3, Fig. 5; Fig. 11) and near all margins except the south (*e.g.*, 3-10-51-22W3, Fig. 11). This geometry suggests that the thickest portions of the reservoir represent multiple, amalgamated sand bodies. In core, amalgamation is further suggested by erosion surfaces and thin shale interbeds within the reservoir sand. On petrophysical logs, very thin deflections and subtle variation in character may indicate the presence of multiple sand bodies (Fig. 8). The presence of relatively large (up to 6 cm), unabraded shale clasts supported by fine sand matrix (Fig. 12) indicates channel deposition in most cored sections. Relatively thick (greater than 20 cm) sets of high angle planar cross lamination suggest large, straight crested bedforms consistent with channel deposition. (Cross lamination is commonly obscured by very high oil saturation; *e.g.*, Fig. 12). Thus the reservoir probably represents multiple amalgamated channel deposits. The deposits are inferred to extend south, probably in a wide linear belt, for an unknown distance.

Permeabilities are greater than 5,000 md in sands saturated with oil (average saturation $\gg$80%) to less than 1,000 md in sands with light oil staining (*e.g.*, 3-10-51-22W3, Fig. 12). Porosities range from greater than 35% in good reservoir sands to less than 30% in argillaceous and/or cemented sands.

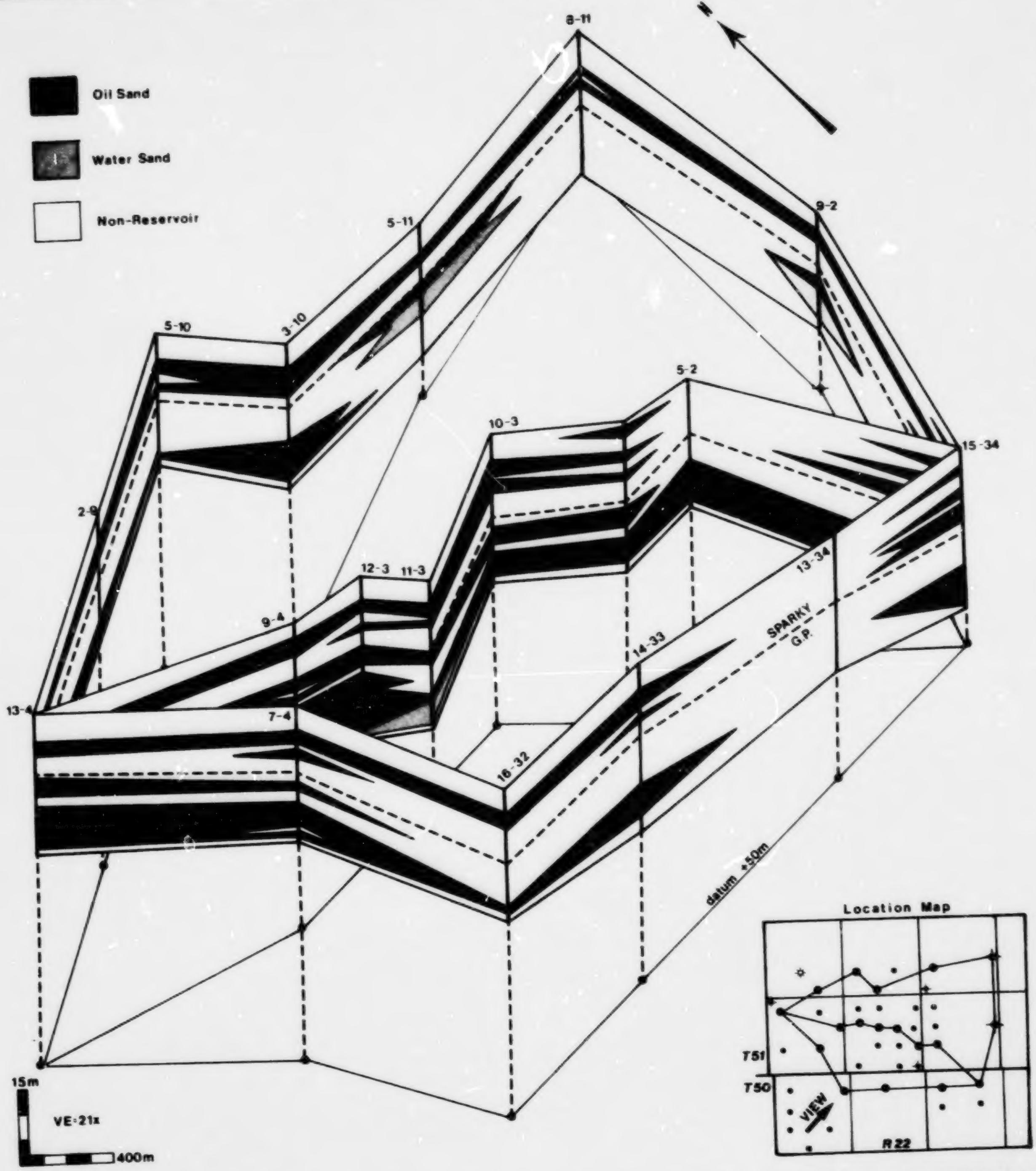

Oil Sand
Water Sand
Non-Reservoir
N
8-11
9-2
5-11
5-10
3-10
5-2
10-3
15-34
2-9
12-3
11-3
9-4
13-34
SPARKY
G.P.
14-33
13-4
7-4
16-32
datum +50m
15m
VE=21x
400m
Location Map
T51
T50
VIEW
R22

Fig. 11 - A three dimensional panel diagram illustrates the distribution of fluids in geometically complex reservoirs in the northeastern portion of the Westhazel Field. The view is toward the northeast (045 degrees); G. P. Sparky strata dip northeast, away from the viewer. Hydrodynamic independence is illustrated by the upper G. P. reservoir in 5-11 (oil over water) and the lower G. P. reservoir in 3-10 (oil only).

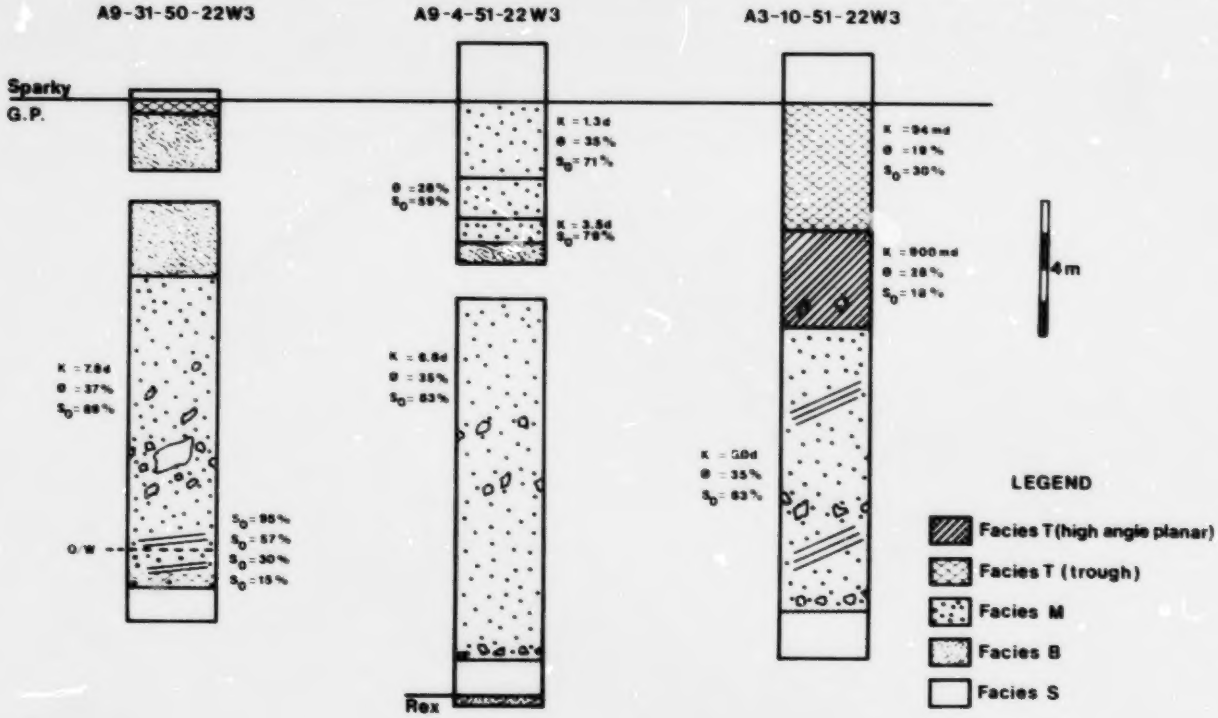


Fig. 12 - Cored sections of the G. P. formation in the Westhazel Field display channel reservoir sand in erosional contact with the basal G. P. shale. The sand is overlain by a Facies B unit in A9-31, by an argillaceous sand (Facies M) with low porosity (28%) in A9-4, and by a ripple laminated sand (Facies T) in A3-10. The upper portion of the channel sand in A3-10 is argillaceous and cemented by clay and calcite. Subangular shale clasts are present in varying, but minor proportions in all three cores. An upper reservoir sand is developed in A9-4. An oil/water contact occurs near the base of the sand in A9-31. Average permeabilities (K), porosities (Φ), and oil saturations (S_o) are shown for the sands. The lithofacies scheme is summarized in Table 1.

Quality of the thick G.P. reservoir is a consequence of depositional features. The anomalous thickness of channel deposit(s) makes possible an exceptionally great thickness of contiguous oil saturated sand. Channel deposition is also responsible for excellent physical properties, insofar as the sands contain very little detrital clay and grain size is slightly coarser than most Mannville sands.

A thinner (up to 5 m) sand of different character is developed in the upper portion of the G.P. in several wells. The sand exhibits lower permeabilities (<1,500 md) and oil saturations (<72%). In several wells, it contains no net pay due to very low permeability and porosity (*e.g.*, 3-10-51-22W3, Fig. 12). In cores, the reservoir comprises predominantly ripple cross laminated and massive sands (Fig. 12) interpreted to represent lower tidal flat and/or washover deposits (see above). In such an environment, sand bodies are relatively thin and rich in detrital clays (commonly recrystallized by diagenetic processes). The marked contrast in quality between this reservoir and the channel sand is a consequence of different depositional processes.

The distribution of aggregate net pay in the two G.P. reservoirs is shown in Figure 10.

The southwestern edge of the Westhazel G.P. Pool is controlled by structure; thick, porous, presumably permeable, sands are structurally low and water saturated (Fig. 8). Portions of reservoirs containing only water or oil over water occur in isolated lows in the northeast corner of Section 4-51-22W3 and Section 3-51-22W3, and in the south half of Section 28-50-22W3. The continuity of the reservoir sands across the lows suggests that the structures are more recent than G.P. deposition.

The relationship between subsidence and sedimentation along the salt solution trough is not clear. On the northeastern edge of the pool, a facies change in both reservoirs from sand to silt and shale coincides approximately with the margin of the trough. On the southeastern margin, at a lower elevation, 12-26-50-22W3 penetrates 8.5 m of G.P. sand which correlates with the channel sand in the Field.

Several wells intersect an oil/water contact in the G.P. reservoirs (Figs. 8, 11). The interface is an irregular surface generally dipping into structural lows with a maximum inclination of 1.5° (1:38). Elevations at the western edge of the pool are higher than at the eastern edge: in 9-31-50-22W3 the oil/water contact is at approximately +92 m; in 12-2-51-22W3 the same surface is at about +80 m. A contiguous 9 m section of oil saturated sand with no bottom water is penetrated by 15-34-50-22W3 (Fig. 11); the base of the reservoir is at +58 m elevation. This may represent: 1) entrapment in a structure that postdates oil migration; 2) failure of high viscosity oil to equilibrate with other fluids; 3) entrapment by a permeability barrier to the west (13-34-50-22W3; Fig. 11); or 4) most probably a combination of the foregoing. Production data (5.6 m³ oil, 328 m³ water in 40 days on production) indicates an oil of high viscosity. The inferred high viscosity may be a cause of entrapment in a low (dynamic disequilibrium); or, it may be the result of such entrapment (increased *in situ* alteration related to increased contact with connate water).

SPARKY FORMATION, SOUTHEAST CELTIC

The distribution of Sparky net pay in the southeastern portion of the Celtic area is illustrated in Figure 13. The gross pattern is controlled by structure. The area encompasses a portion of the major northwesterly trending ridge and the adjoining salt solution trough described above (Fig. 7). In this area, the southwestern margin of the ridge is defined by an open structural low, forming a sinuous belt of oil accumulation in Sparky strata (Fig. 13). The zero net pay contour on the southwestern margin represents an oil/water contact at approximately + 113 m; the northeastern limit of Sparky is an oil/water contact at about + 75 m. The structural high apparently defines a contiguous pool of oil; however, reservoirs in the sandy middle portion of the Sparky are commonly separated in vertical sequence by zones of low permeability that contain little or no oil. This suggests a complex of tabular or lensoid reservoirs which may or may not be interconnected. Variations in net pay within the structurally controlled area of oil accumulation thus reflect depositional and diagenetic features.

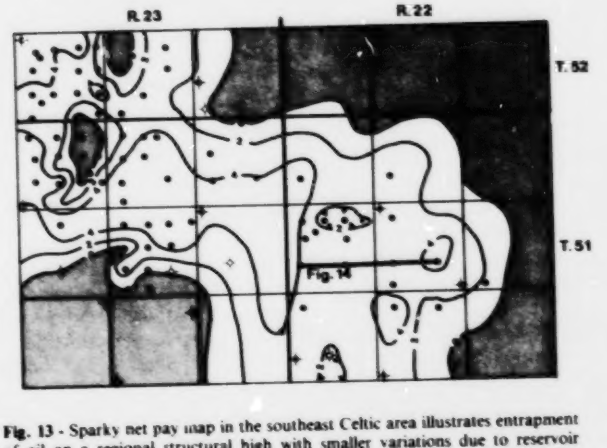


Fig. 13 - Sparky net pay map in the southeast Celtic area illustrates entrapment of oil on a regional structural high with smaller variations due to reservoir geometry. The zero contours in the northwestern corner define an anomalously shaly Sparky sequence. Contour interval is 2m. The location of the east-west cross section in Fig. 14 is shown.

The Sparky formation in the southeast Celtic area is characterized by relatively thin sands of highly variable and generally poor reservoir quality (Fig. 13). No single lithofacies dominates the sand bodies. Low angle planar cross laminated (Facies L) and ripple cross laminated (Facies T) sands are common. Gently curved laminations which suggest larger sinuous crested bedforms (dunes) also occur in Facies T. Facies M sands are distributed throughout the sequence. Clay content within each sand facies is highly variable, but the majority of units exhibit much higher contents than most Mannville sands. Clay and carbonate cement are also relatively abundant. Sandy sequences seldom exceed 7 m in thickness and net pay values are less than 6 m (Fig. 13). Shaly interbeds are abundant defining beds of sand generally less than 1 m thick.

Salient features of the strata are consistent with deposition in the intertidal to supratidal environments interpreted for the Sparky (see above). The abundance of silty and clay rich sands indicates generally lower energy deposition than that in the G.P. and Waseca formations. The majority of clay cemented sands probably formed by the early diagenesis of feldspars and clays in soil horizons (root zones) (Lorsong, 1981) in a warm temperate to sub-tropical climate (Caldwell, 1982). Formation of calcite cement is probably related to entrapment of $CaCO_3$-rich fluids (provided in part by dissolution of shells) between impermeable shales and paleosols (Lorsong, 1981).

Reservoir properties reflect detrital clay content and diagenetic history of the Sparky sands (*cf.* Lorsong, 1981). Sands with low detrital clay contents and very limited diagenesis commonly exhibit permeabilities exceeding 1,000 md, porosities greater than 32% and oil saturations ranging from 60% to 80%. Thickness seldom exceeds 3m (*e.g.*, 4-34-51-23W3) and is commonly less than 0.5 m (*e.g.*, basal sand in 13-20-51-22W3). Argillaceous sands that have undergone limited diagenesis are characterized by permeabilities less than 1000 md (commonly less than 700 md) and porosities ranging from 25% to 35%. Oil saturation ranges from about 50% to 80%. In cemented zones, permeabilities are reduced to less than 100 md, porosities are less than 25%, and oil saturation seldom exceeds 15%.

Lateral continuity of Sparky reservoirs is disrupted in places by anomalous sequences with virtually no sand. An example is illustrated in Figure 13 (northwest corner). The Sparky formation is anomalously shaly in six wells within the area shown in Figure 13, plus A4-11-52-23W3 to the north. In 7-34-51-23W3 and 16-34-51-23W3 the shaly sequence also includes the G.P. formation (Fig. 5). The "shale-out" forms two elongate bodies, each less than 0.75 km by 1.5 km; these are outlined by zero net pay contours in Figure 13.

In cores, the shale is characterized by high organic content and abundant thin (<4 cm) units which contain silt and sand grains, carbonaceous fragments and minor calcareous shell fragments; coals up to 1.5 m thick are also present in three wells. Micropaleontological analyses from two wells (A4-11-52-23W3 and 16-34-51-23W3) yielded an assemblage of foraminifera with very low diversity, dominated by *Hippocrepina* and *Thuramminoida* (Atkin, K. T. J., pers. comm., 1984; Sherrington P. and J. Utting, pers. comm., 1980). These features indicate deposition in quiet, highly restricted, brackish waters. The reason for massive accumulation of almost exclusively fine grained sediment under such conditions in a very small area is not known.

WASECA FORMATION, SOUTHEAST CELTIC AREA.

The Waseca formation in the southeast Celtic area is dominated by a channel deposit which is interpreted to be a continuation of the Pikes Peak deposit (Fig. 6; van Hulten, in press). The Pikes Peak channel trends northeastward to Section 12-51-23W3 where it appears to branch into two separate deposits (Fig. 6, Fig. 15). The narrow western branch is dominated by anomalously thick (>10 m) shale deposits (*e.g.*, 7-35-51-23W3, Fig. 5); the eastern branch comprises sands up to 18.5 m thick (5-29-51-22W3) with overlying thick shales in several wells (*e.g.*, 7-29-51-23W3, Fig. 14).

In core, the channel deposits are very similar to those observed in the Pikes Peak Field (see above; van Hulten, in press; MacEachern, 1982, this volume). The sands are generally fine to medium grained, well sorted, and structureless; high angle planar cross laminations is visible in some intervals. Angular shale clasts (≤20 cm) and reworked Ca,Mg,Fe-carbonate nodules are scattered throughout the sands in all cores; they are concentrated in breccia zones (Facies R) in a few wells (*e.g.*, 5-29-51-22W3, Fig. 16). These clasts are interpreted to be products of bank erosion by channelized flow (Lorsong, pers. comm., 1980; MacEachern, 1982, and this volume). A unit of interbedded sand and shale of varying

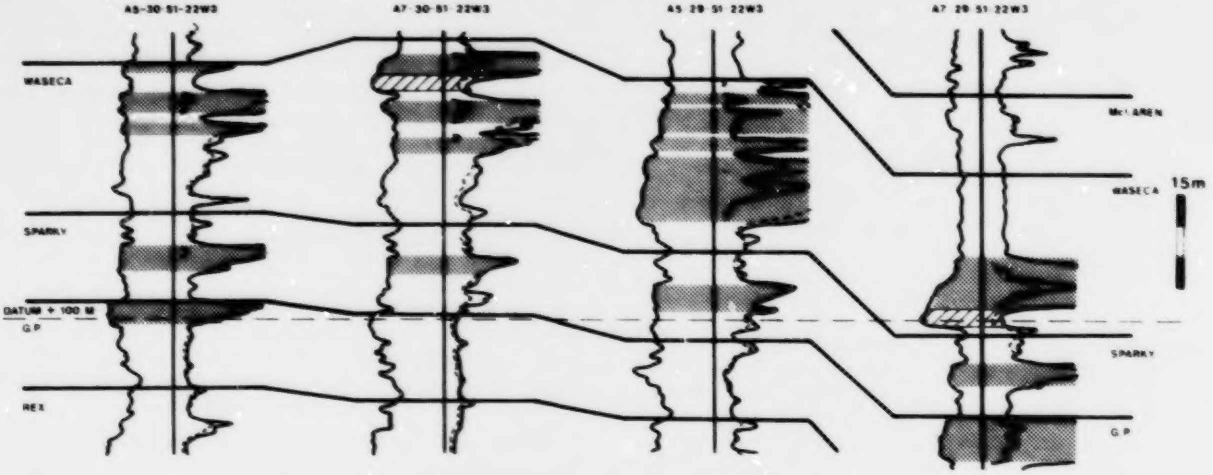


Fig. 14 - Structural east-west cross section (spontaneous potential and resistivity logs) in the southeast Celtic area illustrates the Waseca channel facies (A5-29 and A7-29) and the regional and transitional Waseca facies (A5-30 and A7-30). Cored sections of A7-30 and A5-29 are shown in Fig. 16. Oil saturated sands are shown in grey; water underlying oil is indicated by hachures. In A7-29, an oil/water contact is present at 102 m elevation; the underlying Sparky and G. P. reservoirs are completely oil saturated. An oil/water contact is observed in the uppermost Waseca sand in A7-30; this sand represents an isolated independent reservoir.

thickness overlies the massive sand. Thicknesses and proportions of shale beds generally increase gradationally upward into a thick, shaly interval in several wells (*e.g.*, 7-29-51-22W3, Fig. 14). This unit consists of silty shales which are commonly bioturbated; intervals with well defined silt laminae are also present. Ca,Mg,Fe-carbonate nodules and layers are abundant. The shale body in the western branch of the channel is characterized by similar features.

The channel sands are characterized by excellent reservoir properties. Average permeabilities are greater than 6,000 md, and average porosities range from 32% to 38%. Oil saturations generally exceed 80%. These physical properties reflect grain sizes coarser than typical Mannville sand and very low clay content. The exceptional thickness and reservoir quality of these sands result in uncommonly thick contiguous sections of oil saturation (net pay values up to 18.5 m; Fig. 15).

The Waseca strata adjacent to the channel deposits are largely similar to those observed in other parts of the Celtic Field. They comprise repeated sequences of thinly interbedded sands and shales (Facies B) grading upward into very fine to fine grained reservoir sands less than 6 m thick. The sands are dominated by planar low angle (<15°) cross lamination (Facies L), often in wedge shaped sets with fanning lamination and ripple cross lamination (Facies T) (*e.g.*, 11-35-51-23W3, Fig. 16).

Textures, sedimentary structures and vertical sequences indicate deposition in a wave dominated environment ranging from lower to middle shoreface (Facies B) to beach, upper shoreface or bar top deposits (Facies L and T) (Lorsong, 1982; *cf.* Davidson-Arnott and Greenwood, 1976). Elutriation of the sands by waves resulted in generally low silt and clay contents in Facies L sands; the proportion of these components commonly decreases upward within individual sand units.

Physical properties of reservoir sands reflect detrital clay contents and diagenesis. Permeability in Facies L sands ranges from <100 md to >5000 md. Associated porosites range from 25% to 38%. Low values occur in sands with abundant clay and/or carbonate cement (*e.g.*, 13-30-51-22W3) (*cf.* Lorsong, 1981). Good reservoir sands display average oil saturations greater than 75%; saturations in argillaceous and/or cemented sands are significantly lower (generally less than 60%).

In wells near the western margin of the thick channel sand (*e.g.*, 10-30-51-22W3; 7-30-51-22W3, Fig. 16) the regional facies is characterized by greater volumes of interbedded sand and shale (Facies B), lesser volumes and thicknesses (commonly less than 0.75 m) of sand, and a paucity of well-defined low angle planar cross lamination (Facies L). These transitional strata may include crevasse splay deposits related to the channel (van Hulten, in press).

The northwesterly trending ridge is a locus of oil accumulation in Waseca strata, as in the Sparky (*cf.* Figs. 13, 15). The zero net pay contour on the northeastern flank of the ridge represents an oil/water contact at approximately +102 m elevation. Oil is trapped in the regional strata in the northwest portion of the area (Fig. 15) on a closed structural high (Fig. 7). The major portion of the thick channel sand lies on the eastern flank of another closed high.

Two elongate areas of substantial net pay thickness trend in a northerly direction (Fig. 15). The eastern area (Range 22W3) represents an anomalously thick, contiguous channel sand body. The western area (Range 23W3) represents relatively thin (<7 m) sands in vertically stacked, tabular bodies with geometries similar to the Sparky reservoirs (see above). The intervening area contains a narrow band of low net pay (<4 m) in Range 23W3 reflecting the very shaly strata of the western channel deposit described above. Moderate net pay values between the channel deposits represent rather shaly transitional strata associated with the channel margins (see above).

A relatively thin sand (2.5 m) in the transitional strata in 10-30-51-22W3 exhibits excellent permeability (>3,500 md), porosity (>35%) and oil saturation (>75%). Anomalously high production rates (17.8 m³ of oil/day for 362 days in 1983) reflect excellent reservior and fluid properties (15.8° API oil with a viscosity of less than 2,500 mPa.s at 24°C). The presence of a gas reservoir above suggests high gas saturation in the producing horizon. Similar production rates from a

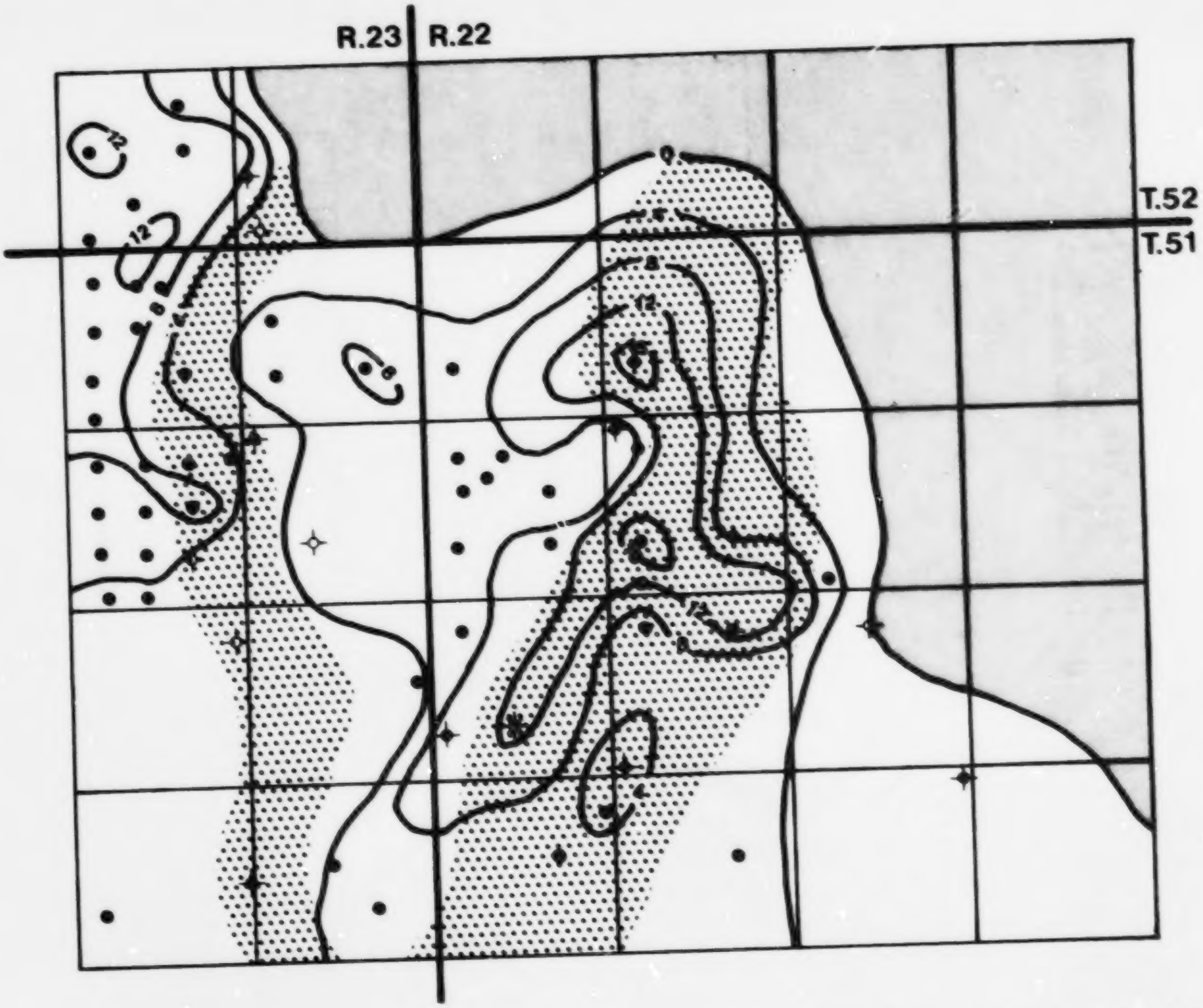


Fig. 15 - An isopach of Waseca net pay in the southeast Celtic area reflects the relationship between oil distribution and depositional facies (contour interval is 4m). The extension of the Pikes Peak channel (Fig. 6) is shown by stippling. The western branch primarily comprises a shaly sequence; the eastern branch contains anomalously thick sands. The remaining areas represent net pay in multiple sands associated with regional and transitional facies.

similar sand were achieved in 15-30-51-22W3, which averaged 22 m^3/day in the first 179 days on production.

The uppermost Waseca sand in 7-30-51-22W3 (Figs. 14, 16) is an independent reservoir with oil over water; 1.2 m of shale and Facies B separate it from the underlying, completely oil saturated sand. Hydrodynamic independence of the reservoir indicates that it is isolated from the regional and channel sands by a permeability barrier; it may be completely enclosed in shaly strata associated with the channel margins. In core, the sand is characterized by poorly defined planar cross lamination (inclined 10° to 20°) and large scale curved lamination; erosional contacts are common. Permeability is anomalously high (approximately 10,000 md), average porosity is 33%, and average oil saturation is 68%.

GAS

In the study area, substantial quantities of natural gas are trapped in the Waseca-Colony interval; small volumes of gas are also present in stratigraphically lower units. The presence of gas rather than oil in the Colony and McLaren formations reflects the generally poor reservoir quality of these strata. Porosities and permeabilities of sands are probably too low for emplacement of substantial quantities of oil. Common lateral and vertical permeability barriers in the Colony and McLaren create complex arrangements of gas, oil and water reservoirs in structurally high areas (Lorsong, 1981).

Gas accumulations occur in the Waseca formation in all fields in the study area. In general, gas is found in the structurally highest region of each field. The gas is associated with oil in that it is trapped in the same structures (see above). However, sands in the upper portion of the Waseca are commonly completely gas saturated; they are separated from oil reservoirs with no identifiable gas cap by less permeable strata. Gas also directly overlies oil in several wells. Production from the Waseca of free gas is limited to three wells in the northwestern corner of the Westhazel Field.

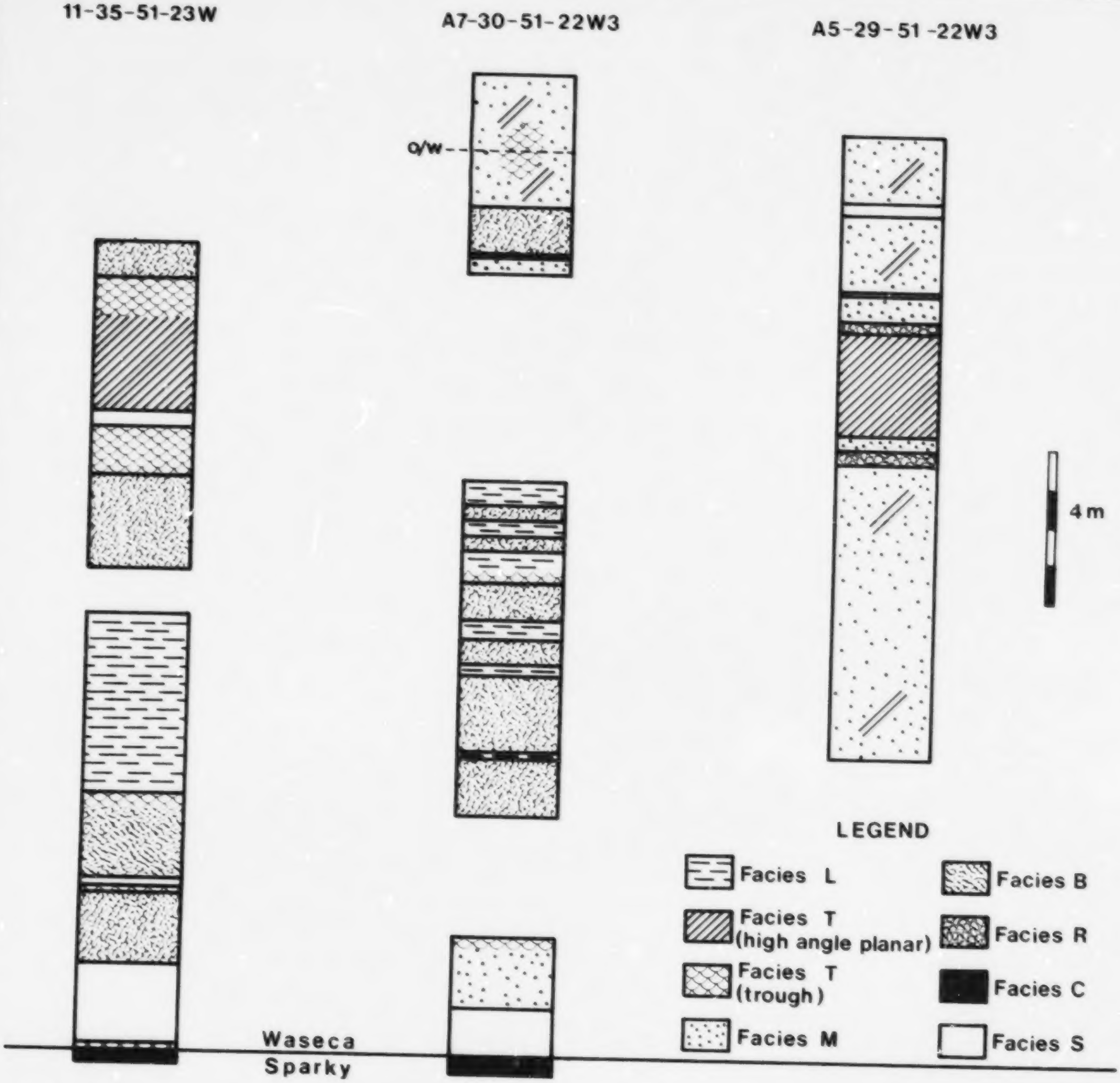

11-35-51-23W
A7-30-51-22W3
A5-29-51-22W3
o/w
4 m
Waseca
Sparky
LEGEND
Facies L
Facies T (high angle planar)
Facies T (trough)
Facies M
Facies B
Facies R
Facies C
Facies S

Fig. 16 - Waseca cored intervals illustrate the nature of regional Waseca strata (A11-35), Waseca channel deposits (A5-29) and transitional sediments (A7-30).

Minor quantities of free gas are present in the Sparky formation in several wells in the Pikes Peak Field and in the Celtic Field (*e.g.*, 11-35-51-23W3). No accumulation of free gas has been identified in the G.P. formation.

CONCLUSIONS

1. Structural relief in the study area is largely the result of subsidence caused by episodic dissolution of Devonian salt in the Prairie Evaporite, mainly after deposition of the Second White Speckled Shale. The most important salt solution structure is a northwest trending ridge created by collapse in a deep, narrow trough coincident with the present edge of contiguous Devonian salt deposits.
2. G.P.-Waseca sediments were deposited in a wave dominated coastal environment characterized by shallow, brackish water and low depositional gradients. Abundant high quality reservoir sand bodies (generally less than 7 m thick) are delineated by common lateral and vertical facies changes to less permeable strata. Anomalously thick (up to 32 m) sands with excellent reservoir properties were deposited in large, vertically aggrading channels.
3. Reservoir geometries created by depositional processes

are complicated by zones of reduced permeability associated with diagenetic clay and calcite cementation.

4. Most hydrocarbons in the study area are trapped in structural culminations along the ridge that parallels the major salt solution trough. Hydrocarbon volumes within the structures and the detailed distribution of fluids in multiple, commonly independent, reservoirs are controlled by the complex geometries of reservoir strata.

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GEOLOGY OF NEILBURG McLAREN POOL WEST-CENTRAL SASKATCHEWAN

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ABSTRACT

The Neilburg McLaren heavy oil pool occurs on the Neilburg high, an elongate structure which originated by differential solution of Devonian salt.

The reservoir zone includes the sheetlike Lower McLaren Sand, a thin coal, and the Upper McLaren Sand. The Lower Sand (5m) and the McLaren coal (0.5m) are rather constant in thickness over much of the map area. The Upper McLaren Sand (1.5m) is less widely distributed and is sporadic in occurrence and thickness.

The McLaren-Colony beds at Neilburg were deposited under marginal marine conditions. The McLaren coal was deposited as peat in a widespread coastal swamp. The sands were deposited in a coastal area not associated with the mouth of a major river. It is uncertain whether sand deposition was wave-dominated or tide-dominated. Locally the reservoir sands and the medial coals are cut by sub-Colony channels (10m to 12m deep). These channels were subsequently partially filled by shale, coal and minor sands.

The southern limit of the Neilburg McLaren Pool is the oil/water contact. Pooled heavy oil in both Upper and Lower Sand is trapped to the northwest by a channel filled with shaly and cemented rocks. To the northeast, heavy oil in the Lower Sand is trapped by a similar channel. In the Upper Sand, pooled oil extends at least 1 km northeastward from the mapped channel suggesting a fluid connection through the upper part of the channel fill. Trapping to the north may be structural or it may result from shaly channel fill.

In addition to the McLaren Pool, there is non-commercial heavy oil in both the Sparky and Lloydminster main sands on the Neilburg structure. Within each of these heavy oil accumulations (McLaren, Sparky, Lloydminster), the interwell variation in elevation of the oil-water contact is ±3m to ±4m. The interwell variation is controlled by capillary and wetting properties of the reservoir rocks, not by "hydrodynamics".

INTRODUCTION

Wells completed in the Neilburg McLaren Pool are some of the most prolific producers of the Lloydminster heavy oil belt. It is antcipated that primary recovery will be high and the original reserves per well spacing unit will be large compared to most pools in the Saskatchewan portion of the Lloydminster area.

This paper is a progress report on geological aspects of the heavy oil occurrence in the McLaren sandstones in the Neilburg Field. McLaren oil is pooled on a structural high but stratigraphic barriers, tentatively interpreted as channel fills, interrupt the tabular reservoir sandstones at the northeastern and northwestern margins of the main oil pool. Presumably, similar reservoirs and traps occur elsewhere in the McLaren of the Lloydminster area.

The work done includes a core study on 13 wells (Richardson) and a study of well logs and fluid distribution (Richardson and Vigrass). Richardson plans additional environmental work as part of her continuing studies.

LOCATION

The Neilburg McLaren Pool (Neilburg Field) and the study area are situated in the southern part of the main Lloydminster heavy oil area of west-central Saskatchewan (Fig. 1). Pool boundaries, as presently defined by the Saskatchewan Department of Energy and Mines (SEM), embrace Sections 7 and 18, Twp. 46, Rge. 25W. 3M. and Sections 12 and 13, Twp. 46, Rge. 26W. 3M. Additionally the developed area extends eastward to include parts of Sections 15, 16, 17, 20, 21 and 22, Twp. 46, Rge. 25W. 3M. (*see* Figs. 4, 5, 6). The study-area covers 168 km^2 (65 sq. mi.) including Twp. 46, Rge. 25W. 3M. and the eastern half of Twp. 46, Rge. 26W. 3M.

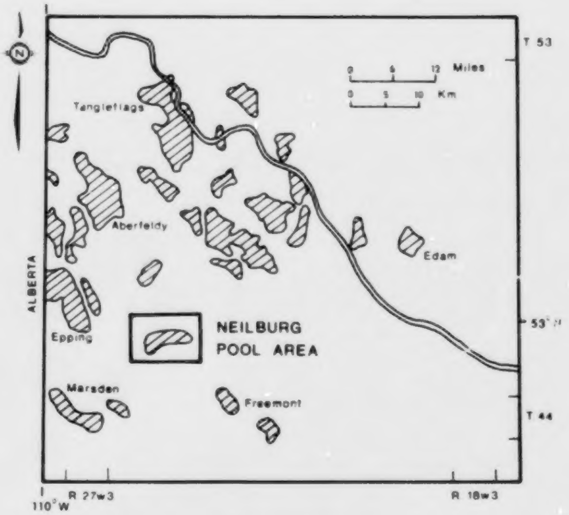

Fig. 1 - Index map showing location of the Neilburg McLaren Pool with reference to other heavy oil pools of the Lloydminster region of Saskatchewan.

PRODUCTION AND RESERVES

The Neilburg McLaren Pool produces oil with density 966 kg/m^3 (15°API). Average oil production per well within the officially defined pool area was 5.1 m^3/d (32 BOPD) in 1982 when 16 wells operated and 3.9 m^3/d (25 BOPD) in 1983 when 19 wells operated. Several wells have had average oil production of 9 m^3/d to 11 m^3/d (55 BOPD to 70 BOPD) over the first three years of their life.

Reserves per well are large, especially considering that the average net pay is only 4.8 m (15.8 ft.) in the official pool area

(Saskatchewan Energy and Mines, 1983). In the defined pool area, oil-in-place per well spacing unit of 16.2 ha (40 acres) is booked at 122,000 m^3 (770,000 barrels) based on an average porosity of 25 percent, water saturation of 30 percent and formation volume factor of 1.111 (SEM, 1983). The primary recovery anticipated by SEM is 11 percent so booked initial reserves average 13,500 m^3 (85,000 barrels) per well spacing unit in the official pool area. The anticipated primary recovery factor is more than double the average primary recovery factor (5 percent) for the Lloydminster area as a whole.

Initial primary reserves are booked at 337,000 m^3 (2.4×10^6 barrels) for the 28 wells capable of production in the official pool area. The total area currently developed has 72 completed wells and covers 1,166 ha (2,880 acres). Initial primary reserves for the total developed area are estimated to be in the order of 950,000 m^3 (6×10^6 barrels).

STRATIGRAPHY

MANNVILLE GROUP

The Lower Cretaceous Mannville Group of the Lloydminster region is a sandstone-shale sequence with minor coals that lies unconformably on older rocks and is overlain by the marine Joli Fou Formation (Vigrass, 1977). A number of depositional cycles are recognizable and several of these cycles (especially those in the middle part of the Mannville) can be traced, by means of mechanical logs, for long distances within the region. Several of the cycles consist of shaly rocks overlain by sandsone. A thin bed (or beds) of coal occurs at or near the top of some of the cycles.

Nomenclature of members or formations within the Mannville Group has its roots in studies of the 1940's (Vigrass, 1977). The subdivisions and nomenclature at Neilburg, as applied during this study, are shown in Figure 2.

COLONY-McLAREN MEMBERS

General Relationships

Over most of the study area, single layers or packages of layers within the Colony-McLaren sequence can be traced from well to well by using mechanical logs or lithologies derived from cores. An example is shown in Figure 3 where correlations can be made with reasonable confidence in the cored wells extending eastward through the Neilburg Field from A9-13-46-26 to A7-15-46-25. There are about 90 wells in the study-area with a "normal sequence" of strata in the upper part of the McLaren. In areas of normal lithological sequence, correlation between wells can be made with logs and cores or with mechanical logs alone.

Within the study-area, at least seven wells have anomalous sequences of strata in the middle part of the Colony-McLaren succession. Wells showing anomalous lithological sequence in Figure 3 are A15-15-46-25 (cored) and D16-13-46-26 (not cored). One cannot correlate the anomalous sequence with the normal lithological sequence.

Normal Lithological Sequence

The normal lithological sequence of Colony-McLaren strata, based on cores from 12 wells, is described below. The sedimentary structures, commonly not obvious because of oil staining, are a composite of those observed in the 12 cores.

Top of described sequence. Overlain by grey Joli Fou shale containing shell fragments.

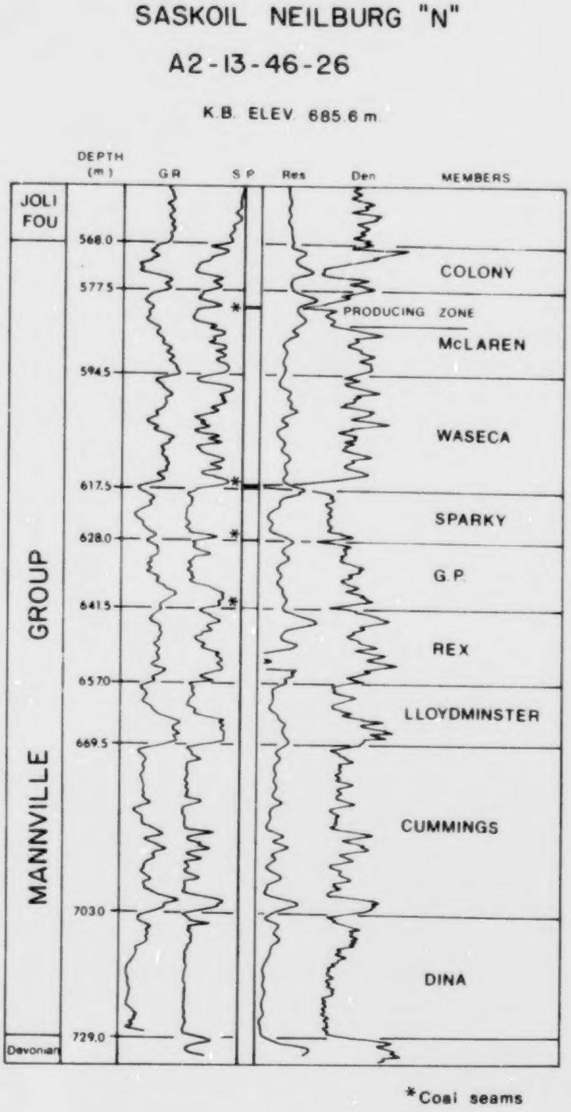

Fig. 2 - Mechanical logs of a Neilburg Field well showing Mannville subdivisions and the producing zone.

Colony Member (10m - 12 m)

9. **Silt and shale** (4m - 7m). interlaminated. Carbonaceous in part. Lenticular bedding, burrows, root traces, iron carbonate concretions, soft sediment deformation.

8. **Sand and shale** (5m - 6m), interbedded. Sand is fine to very fine grained, good porosity except where locally cemented with iron carbonate, weak to moderate oil staining. Ripples, planar laminations, small-scale trough cross laminations, flaser bedding, bioturbation, burrows, root traces, rootlets.

McLaren Member (15m - 18m)

7. **Upper oil sand** (1m - 3m). Very fine grained, well sorted, abundant coal clasts, friable to loose, heavy oil stain.

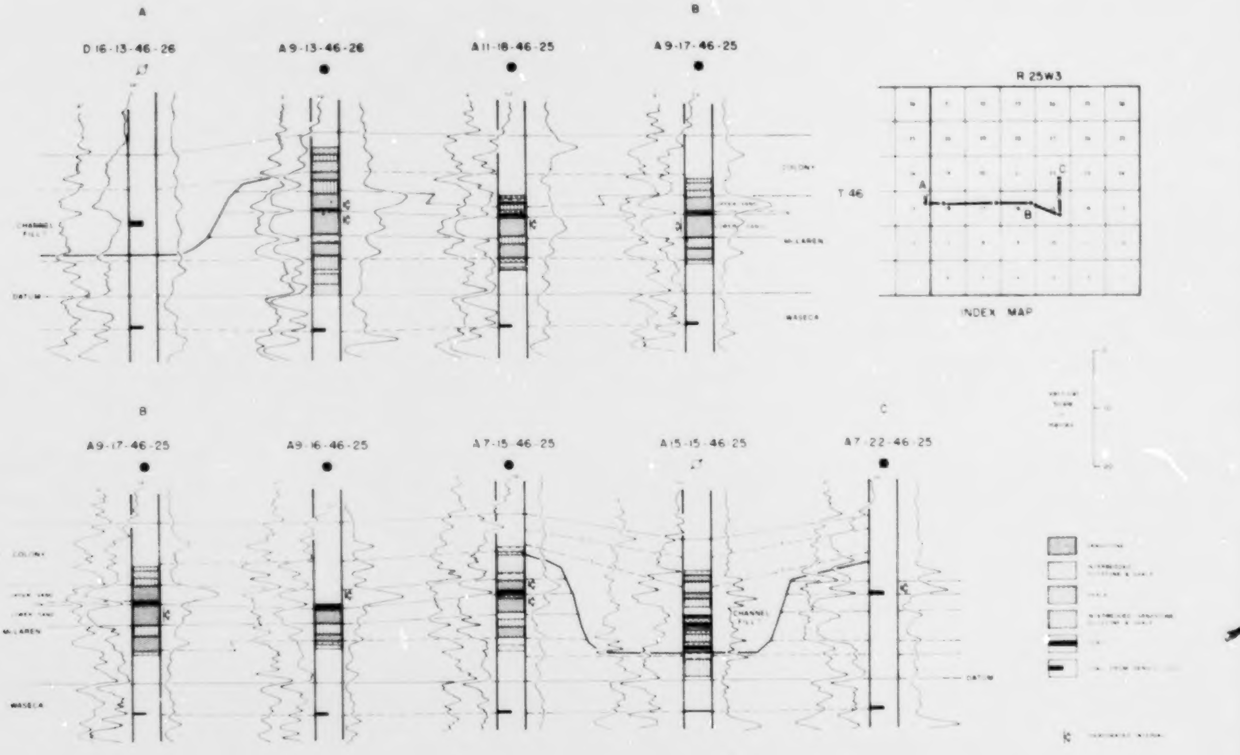

Fig. 3 - West-east correlation section, Neilburg Pool area. The section shows possible channelling through the Neilburg Pool sands. Maximum vertical exaggeration is 75×.

Horizontal laminations, low angle planar lamination, ripples, climbing ripples. (This oil sand may be assigned to the Colony by other authors).

6. **Coal and shale** (0.2m - 1m). Coal is black, dull to subvitreous with fusain layers, contains pyrite nodules. Commonly, shale (0.1m - 0.3m) containing detrital coal underlies the coal seam. Locally, shale (0.1m - 0.3m) overlies the coal.
5. **Lower oil sand** (3m - 4m). Very fine grained, well sorted, generally oil stained. Contains coal clasts and coal laminations outlining structures. Planar laminations, wavy bedding, planar cross stratification, climbing ripples, mild bioturbation, rare burrows, iron carbonate coating in small local areas.
4. **Shale and sand** (1m - 2m), interlayered, generally on a scale of 0.1 m to 0.2 m. Lenticular bedding, wavy bedding, planar laminations, small scale trough cross stratification, bioturbation, burrows.
3. **Sandstone** (1m - 3m), very fine grained at base to fine grained at top, poorly sorted. Commonly cemented by clay and calcite in the lower half but is friable in the upper half. Oil stained in upper half. Coal laminae at top. Horizontal laminations, low angle planar laminations, ripples, iron carbonate concretions, mild bioturbation.
2. **Mudstone and sand** (6m - 7m). Composed of clay shale at the base with increasing silt lenses and laminae upward. One or two sand layers (1m) are interlayered, generally in the middle or upper part. Primary structures occur particularly in the silty shales: planar laminations, lenticular bedding, wavy bedding, small scale trough cross stratification, ripples, fracture with offset, bioturbation, *Ophiomorpha* burrows, iron carbonate cemented layers and nodules.

Waseca Member (23m)

1. **Sandstone** (1m - 2.5m). Very fine grained, poorly sorted, coal clasts in lower part. Bioturbated, *Ophiomorpha* burrows.

Base of described sequence. The base of this persistent sandstone is 3m to 4m above a widespread coal seam in the upper part of the Waseca Member (Fig. 3).

Anomalous Lithological Sequence

An anomalous lithological sequence in the middle part of the Colony-McLaren has been cored in the A15-15-46-25 well (*see* Fig. 3):

Top of core.

Colony Member

Shale (1m). Grey and green grey, coal clasts and laminae, pyritic. Bioturbation (Probably the base of Unit 9, Normal Sequence).

Sandstone, shale, and siltstone (6m), interlayered. Sandstone is very fine grained, commonly cemented by clay or iron carbonate. Heavily bioturbated in part. Light oil staining in less cemented layers. (This is possibly Unit 8, Normal Sequence).

Missing core? (2m). (Mechanical logs indicate a thin coal bed and shale).

Anomalous Sequence

Coal and shale (0.7m), interlayered. Coal dull, pyritic.

Sandstone (0.2m), coarse grained, poorly sorted, unstained.

Shale and siltstone (3m), interlayered. Lenticular bedding, detrital coal, rootlets, bioturbated, burrows, pyritic.

Coal and shale (0.5m), interlayered.

Sandstone (0.2m), fine grained, large coal clasts, bioturbated, unstained.

Base of anomalous section?

Shale and siltstone (1.5m), interlayered. Green-grey and grey. Bioturbated, rootlets. (Possibly Unit 2, Normal Sequence).

Sandstone, siltstone, and shale (2.5m) ?, interlayered. Sandstone is very fine to fine grained, light oil stain. Burrows, rootlets, load structures, iron carbonate concretions, climbing ripples, trough cross lamination (Probably Unit 2, Normal Sequence).

Base of core.

Both core and logs indicate that Units 3, 4, 5, 6, and 7 of the normal sequence are missing in the A15-15-46-25 well. These units have been replaced by a thinner sequence consisting largely of shale with three coal intervals. The Colony-McLaren sequence in the A15-15-46-25 well is 5m thinner than in nearby wells (Fig. 3).

On the basis of mechanical logs, anomalous Colony-McLaren sequences have been identified in these additional wells: A9-15-46-25; A6-19-46-25; C13-21-46-25; B16-28-46-25; A11-13-46-26; D16-13-46-26 (Fig. 3; Fig. 5). Mechanical logs suggest that the lithology varies considerably between these wells. In several of the wells, the Colony-McLaren sequence is thinner than normal. Some contain cemented sandstone layers.

McLAREN PRODUCING ZONE

The producing zone at the Neilburg McLaren Pool includes a lower sand (Unit 5), medial coal (Unit 6), and an upper sand (Unit 7). Some of the Neilburg wells have been completed in the lower sand, others in the upper sand, and many have been completed in both (Fig. 3).

The medial coal unit can be identified with considerable confidence by means of mechanical logs, especially where density-neutron logs are available. The gamma ray log suggests that locally the unit grades laterally to a coaly shale. The coaly unit, which is generally 0.5m - 1.0m thick, is present in most parts of the study area. It cannot be identified with certainty in any of the wells with anomalous sequences and it appears to be absent in the wells shown in Sections 12 and 23, Twp. 46, Rge. 25W. 3M. (*see* Figs. 4, 5, 6).

The lower oil sand of Unit 5 (hereafter referred to as McLaren Lower Sand) can be identifed and traced because of its position below the coal unit. The Lower Sand is widely distributed and is considered to be present in all wells except those with anomalous sequences. Average thickness of the Lower Sand in the study-area is about 5m, and thickness does not vary by more than a metre or so from well to well. The sand is generally very fine grained, very well sorted and has excellent reservoir properties. In a few wells the reservoir is poor because the sand is shaly or is cemented by calcite or clay.

The McLaren Upper Sand (Unit 7) its identified largely on its position above the McLaren coal. In contrast to the Lower Sand, it is subject to variations in sand thickness and shaliness (*see* A11-18-46-25, Fig. 3). The Upper Sand cannot be identifed in sections with anomalous sequences and it appears to be absent over large portions of the study-area (*see* Fig. 6). The Upper Sand is as much as 3.5m thick but its average thickness, in areas where it is identifiable, is 1.5m. The sand is generally very fine grained and, except where thin, it tends to be well sorted with excellent reservoir properties. In a number of wells in the developed area, the Upper Sand unit can be identified but is not an effective reservoir because of shaliness or because the sand is cemented by calcite or by clay (*see* Fig. 6).

STRUCTURE AND FLUIDS

LLOYDMINSTER MAIN SAND

The Lloydminster main sand is a remarkably persistent reservoir unit and mechanical logs suggest that it has few stratigraphic complications within the study area. The structure contour map (Fig. 4) is based on subsurface data only. Distribution of oil above water in the main reservoir was used in interpreting the structure.

The reginal dip of the Lloydminster is southward at about 2 m/km (10 ft./mi.). An irregular, pronounced structural high extends five miles eastward from Section 13, Twp. 46, Rge. 26W. 3M. (Neilburg structural high). Elevations and fluid distribution in wells to the north indicate a narrow but persistent east-west low that probably passes through the northern part of Sections 19 and 20, Twp. 46, Rge. 25W. 3M. On the Neilburg structural high, a thin and non-economic oil zone occurs in the Lloydminster sandstone at elevations above about +28m. Evidence for the structural reversal is based in part on wells in the northeastern part of the study area where water-bearing Lloydminster sandstone occurs at elevations of +28m to +38m. In order to trap oil in the Lloydminster main reservoir in the Neilburg structural high, the structural reversal is at least 4m.

A structural high underlies about 10 sections in the northern part of the study area (Fig. 4). Pooled Lloydminster oil (largely non-commercial to date) occurs at elevations above about +30m in this area. In Figure 4, a structural low separates this Lloydminster accumulation from the accumulation on the Neilburg structural high. It is possible that the two accumulations are joined in the vicinity of Section 24, Twp. 46, Rge. 26W. 3M.

Small highs are interpreted in the southern part of the study area. The western high has non-commercial Lloydminster oil accumulated above approximately elevation +20m (Fig. 4). We have interpreted a structural reversal between this accumulation and the Neilburg structural high.

SPARKY MEMBER

Structural mapping of the Sparky Member is complicated by facies changes or channelling (or both) that occur in and near the eastern part of the Neilburg Field. A normal or regional Sparky sandstone is widespread and the structure of this nor-

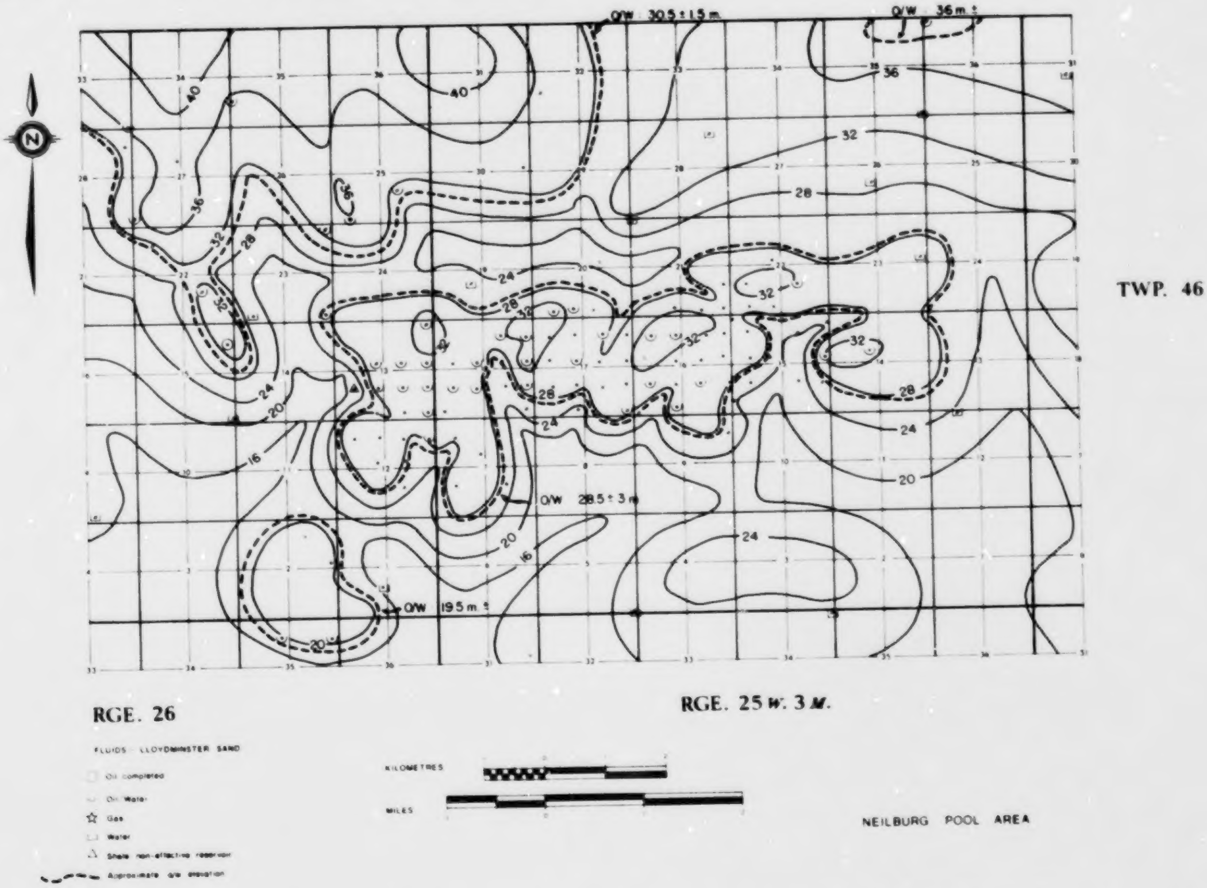

Fig. 4 - Structural contours (above sea level) on top of the Lloydminster Member (main sand). Contour interval is 4 metres. Indicated are fluid content for crucial wells and approximate intersection of oil/water interface with the cover rock.

mal Sparky sandstone imitates the Lloydminster structure over much of the map area.

The fluid content of the Sparky sandstone is complicated by the stratigraphic variations. Several oil wells have been completed in anomalous Sparky sequences near the eastern end of the Neilburg Field. In addition, there are many non-commercial occurrences of oil above bottom water in regional Sparky sandstone. At least 59 of these non-commercial occurrences are clustered on the Neilburg structural high. On the Neilburg structure, the elevation of the oil-water interface in regional Sparky ranges from +62m to +70m (*see* Fig. 7 and later discussion).

McLAREN LOWER SAND

Isopachs of the interval from the Lloydminster Member to the McLaren coal range from about 75m to 80m in the study area. The thickness variations are small and do not appear to be systematic. As a result, the McLaren Lower Sand structure mimics the Lloydminster structure to a considerable degree. The same structural highs and lows are interpreted even though there may be slight differences in amplitude and slight changes in geographic position (Fig. 5).

Pooled oil occurs in the McLaren Lower Sand on part of the Neilburg structural high. The southern and southwestern edges of the Lower McLaren accumulations are determined by the oil-water interface at an elevation of +98m to +106m (*see* later discussion). Shaly anomalous McLaren sequences appear to form the trapping mechanism at the northwestern edge of the accumulation (Fig. 5). Water occurs in the Lower Sand at a high elevation in A1-23-46-26, as it does over most of the north-western part of the study area (Fig. 5). A thin gas leg occurs at A4-25-46-25.

Anomalous McLaren sequences (shale, coal, cemented sandstone) occur in A9-15-46-25 and A15-15-46-25 (Figs. 3, 5). The trap at the northeastern edge of the Lower Sand accumulation is controlled by this belt of anomalous rocks. Water occurs in the Lower Sand at high elevation in several wells immediately to the northeast of this belt (Fig. 5).

The trap at the northern edge of the Lower Sand pool may be structural, as suggested on Figure 5. Alternatively, the belts of non-effective reservoir shown in Figure 5 may be continuous across the northern edge of the pool.

A separate heavy oil pool in the Lower Sand is interpreted on the structural high in Section 2, Twp. 46, Rge. 26W. 3M. The oil-water interface on this structure is about 9m lower than the interface on the Neilburg structural high (Fig. 5).

McLAREN UPPER SAND

The McLaren Upper Sand is separated from the Lower Sand

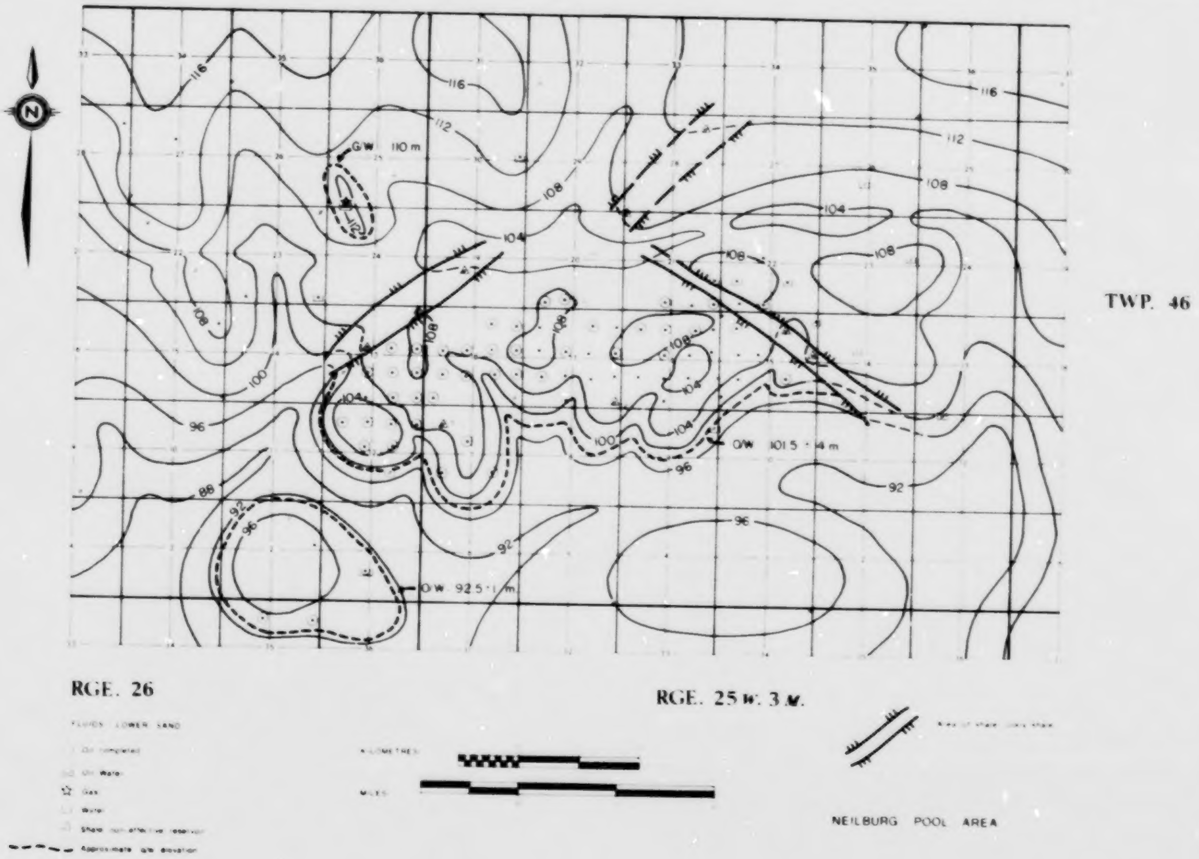

Fig. 5 - Structural contours (above sea level) on top of the lower producing sand of the McLaren Member (base of coal). Contour interval is 4 meters. Indicated are fluid content for crucial wells and approximate intersection of oil/water interface with the cover rock.

by a metre or less of strata. As a result, the structural form of the Upper McLaren Sand is similar to the structural form of the Lower Sand.

Fluid distribution in the Upper Sand is controlled to a considerable extent by the distribution of effective reservoir sands. In addition to the 7 wells with the anomalous lithological sequence, where the Upper Sand cannot be identified definitely, the Upper Sand appears to be absent ("shaled out") above the identifiable coal unit in many wells within the study area. Locally within the developed area, there is no effective reservoir because of shaliness or cementation (Fig. 6).

The main oil accumulation in the Upper Sand is on the Neilburg high. A single well at the south edge of the Field (A9-16-46-25) has an observed oil-water interface at about +99m. The southern edge of pooling on the Neilburg structural high is the oil/water interface (Fig. 6). The northwestern edge is controlled by stratigraphic changes reflected in replacement of effective reservoir by shale (A6-19-46-25; 4 wells in Section 13, Twp. 46, Rge. 26W. 3M.). The northern edge of pooling may be structurally controlled (as suggested on Fig. 5) or it may be stratigraphically controlled (as shown on Fig. 6). It is suggested that there is local reservoir continuity between the Upper Sand and the Lower Sand on the Neilburg structure.

At the northeastern edge of the developed area, several wells (A11-14, A8-21, A3-22, A5-22, A7-22, all in Twp. 46, Rge. 25W. 3M.) contain pooled oil in the Upper McLaren Sand whereas water occurs in the Lower Sand. The Neilburg McLaren Pool appears to extend farther eastward in the Upper Sand than it does in the Lower Sand. In this vicinity, a stratigraphic trapping mechanism appears to be entirely effective for the Lower Sand but ineffective (or only partially effective?) for the Upper Sand. On the Neilburg stucture, the northeastern edge of pooling in the Upper Sand is presently not defined.

Current well control suggests three other areas of Upper McLaren Sand oil pooling. Two wells (A1-35-45-26, A6-1-46-26) suggest an accumulation that is probably separate from pooling on the main Neilburg structure. Additional separate pools are interpreted west (Section 14, Twp. 46, Rge. 26W. 3M.) and northwest (Section 29, Twp. 46, Rge. 26W. 3M.) of the Neilburg developed area (Fig. 6).

ORIGIN OF STRUCTURE

The local structures are presumed to result mainly from differential solution of Devonian salt (Elk Point, Duperow). The maximum local structural relief is about 12m (40 ft.). Constancy of the Lloydminster-McLaren isopach suggests that little differential salt solution accompanied Mannville deposition in the study area. The local structure of the Lloydminster,

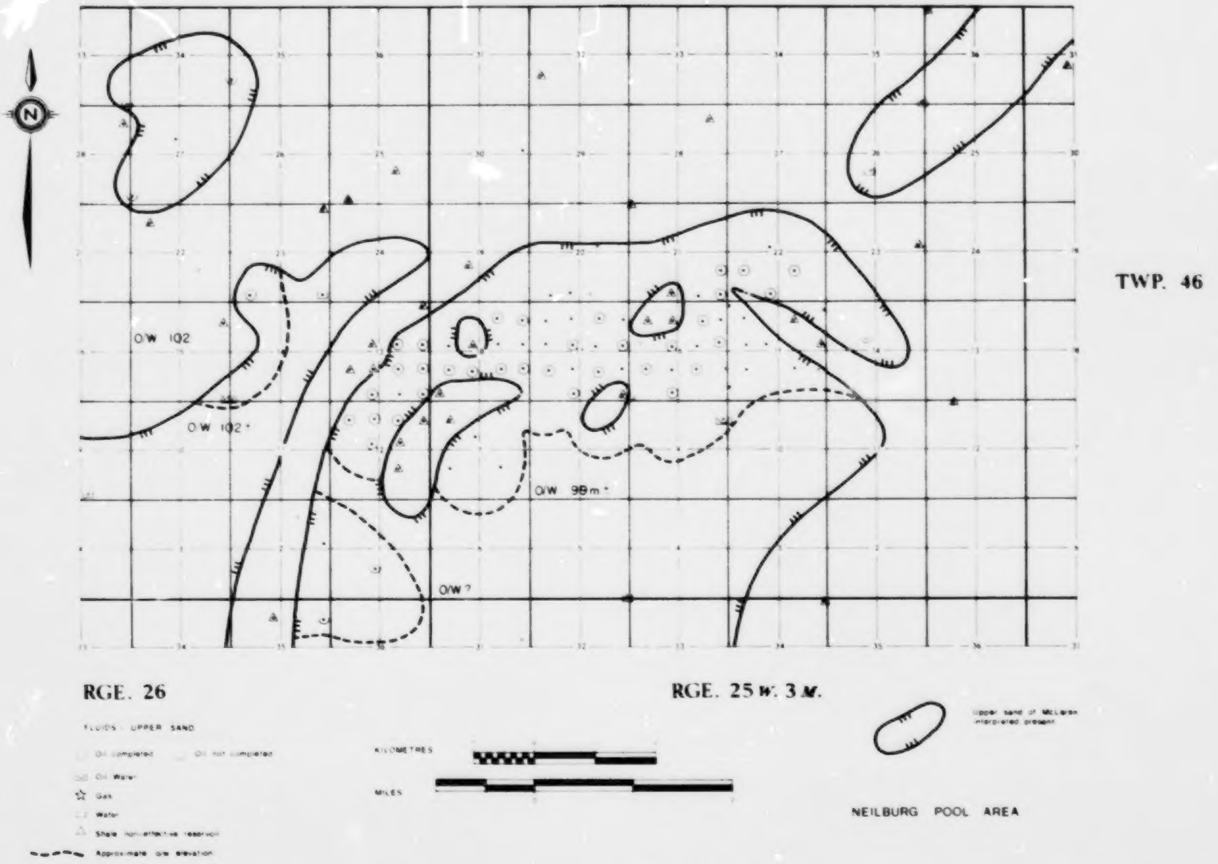

Fig. 6 - Distribution of the upper producing sand of the McLaren Member. Indicated are fluid content in crucial wells and approximate intersection of oil/water interface with cover rock.

Sparky, and McLaren was formed since early Cretaceous (middle Albian) time.

Continuity, length and shape of the Neilburg structural high suggests the possibility of an underlying Devonian reef or bank. It is speculated that the carbonate body was flanked by evaporitic beds which have been partially removed by post-Albian subsurface solution.

ELEVATION OF OIL-WATER INTERFACES

Variations of the elevation of observed oil-water interfaces on the Neilburg structural high are shown in Figure 7. The position of the observed interface in individual wells is based on mechanical logs.

In the Lloydminster sandstone on the Neilburg structure, 37 wells have oil above water as identified from resistivity and porosity logs. Elevation above sea level of the observed oil-water interface ranges from 25.8m to 31.6m. On a geographic basis, there appears to be no systematic slope to the observed oil-water interface. There appears to be a normal frequency distribution around a modal class with elevation +28.5m to +29.4m (Fig. 7).

In the Sparky sandstone (normal or regional lithological sequence) on the Neilburg structure, 59 wells have been identified as having oil above water. Elevation above sea level of the observed oil-water interface ranges from 62.4m to 69.8m. There is no discernable systematic slope to the interface. A normal frequency distribution is suspected with a modal class of +66.5m to +67.4m (Fig. 7).

In the Lower McLaren Sand reservoir, the oil-water interface has been identified tentatively in 19 wells on the Neilburg structure. The observed elevations, based on mechanical logs, range from +97.8m to +105.5m. On a geographic basis, there does appear to be a distinct grouping of elevations: most of the wells with a high observed oil water interface (+102.8 to +105.5) appear to occur along a trend from the southwest corner of Section 16 to the northwest corner of Section 15, Twp. 46, Rge. 25W. 3M. Almost all of the remaining wells (9 wells) have elevations between +97.8m and +100.7m. The wells with a low oil-water interface are found across the southern part of the developed area.

Analysis of the data suggests that the elevations of the observed oil-water interfaces in the Lloydminster, Sparky, and Lower McLaren reservoirs on the Neilburg structure are controlled by capillary and wetting properties of the reservoir rocks. There is no evidence of "hydrodynamic" control such as systematic slope to the oil-water interfaces. In water-heavy oil systems where there is little density difference between oil and water, the buoyancy effect is small, so that relatively minor changes in wettability-capillarity will result in sizeable

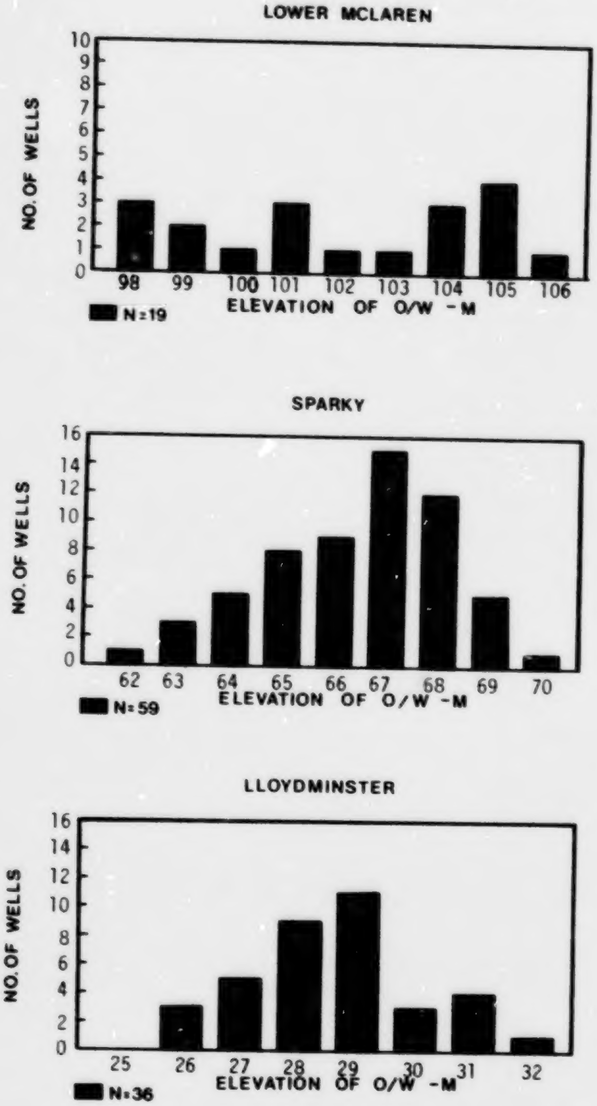

Fig. 7 - Distribution of elevation of oil-water contacts within the Neilburg Field as interpreted from resistivity logs. Frequency diagrams are based on 19 wells for lower McLaren oil sand, 59 wells for regional sand facies of the Sparky, and 36 wells for the Lloydminster sand.

variations of elevation of the observed oil-water contact (Mayer-Gurr, 1976, p. 35-41). For the Lower McLaren Sand, the local high areas in the observed oil-water interface are presently unexplained. Further investigation is planned.

DEPOSITIONAL ENVIRONMENTS

DEPOSITIONAL SETTING

In a related study, Dr. Vasu Nambudiri has examined palynomorph assemblages in 30 samples from the upper Mannville at Neilburg. Continentally-derived fern spores and conifer pollen grains are dominant. Small numbers (2%) of dinoflagellates and/or hystrichosphaerids were identified in the upper part of the Waseca, in Units 2, 3, 6, and 7 of the McLaren, and in Units 8 and 9 of the Colony. In 3 samples, plants typical of a coastal swamp are indicated. The relevant palynomorph is *Taxodiaceaepollenites*, related to extant *Taxodium* or swamp cypress. In two cases this palynomorph occurs with dinoflagellates or hystrichosphaerids. The assemblages with *Taxodiaceaepollenites* occur in the upper Waseca and Units 2 and 6 of the McLaren. The palynology suggests that the McLaren and Colony rocks are derived from coastal sediments deposited in an environment transitional between terrestrial and marine.

DEPOSITIONAL MODEL CHARACTERISTICS

Any depositional model must incorporate the vertical succession of strata, lateral relationships, lithology and grain size, biogenic features, and sedimentary structures observed in the core.

Normal Lithological Sequence

A depositional model for the normal (regional) sequence must incorporate these characteristics:

1) There is a general coarsening upward from the base to the top of the McLaren and a general fining upward from the base to the top of the Colony.

2) *Ophiomorpha* (?) burrows in Units 2 and 4 (McLaren) suggest a nearshore marine environment.

3) Characteristics of the McLaren suggest an increase of energy levels (tides, waves or currents) upward. The lowest division (Unit 2) is mainly silty shale with extensive bioturbation, suggesting low energy levels. Silt ripples, subsequently eroded to form silt lenses, suggest a slightly higher energy level. Root traces suggest the possibility of temporary subaerial exposure. The interbedded shale, siltstone and sandstone of Units 3 and 4 indicate alternating suspension and traction load with changing energy levels. Unidirectional ripples suggest higher energy levels and increased sediment supply. The Lower McLaren Sand (Unit 5) is very fine grained and well sorted with "coffee grounds" of coal. There are horizontal laminations and well-formed unidirectional ripples, possibly wave generated. Bioturbation and burrowing is not as evident as it is in the lower strata, suggesting a higher energy level. The Lower Sand is persistent over a large area, apparently existing as a sheet of rather constant thickness (about 5 m) over more than 150 km². The McLaren coal (Unit 6) is also very persistent over a similar area, despite it being thin (about 0.5m). The Upper McLaren Sand (Unit 7) is thin (about 1.5m). Occurrence of the Upper Sand is sporadic and it is less widespread than the Lower Sand.

4) Characteristics of the Colony sequence suggest that energy levels decreased as deposition proceeded.

5) Palynology suggests recurrences of coastal swamp vegetation.

Anomalous Lithological Sequence

A satisfactory depositional model must incorporate these features:

1) An anomalous sequence composed largely of coal, shale, and minor sand (cemented locally) replaces the upper part of the "normal" McLaren. Dinoflagellates within this anomalous sequence suggest marine influence during deposition.

2) The Anomalous Sequence is thin compared to the Normal Sequence.

3) The Anomalous Sequence is distributed in long narrow bands. Locally, near the northeastern end of the Neilburg Field, the band of shale, coaly shale, and cemented sandstone is at least 2 km long and, locally is less than 0.4 km wide (Fig. 5).

4) There is no definite evidence from nearby wells that the Normal Sequence grades laterally into the Anomalous Sequence.

Comments

We have not decided on the exact nature of the McLaren-Colony depositional model at Neilburg. We consider that the Normal Sequence was deposited in a coastal environment not associated with a major river mouth. We consider that the McLaren coal (Unit 6) was deposited in a widespread coastal swamp. We are unsure whether the deposits are wave-dominated or tide-dominated but favour the latter.

Based largely on geometry, we consider that the Anomalous Sequence represents a channel fill. The exact nature of the channel (whether formed subaerially or subaqueously, whether tidal or distributary) is uncertain.

CONCLUSIONS

The Neilburg McLaren reservoir zone was deposited under marginal marine conditions. The medial coal was deposited as peat in a widespread coastal swamp. The Lower Sand is sheetlike and underlies most of the study area (168 km^2). The Upper Sand is less widely distributed and more sporadic in distribution. Locally the reservoir zone is cut by sub-Colony channels (10m to 12m deep) that were partially filled by shale, coal, and minor sand.

The heavy oil in the McLaren at Neilburg is pooled in a combination structural-stratigraphic trap. The oil pool occurs on an isolated, elongated structural high but the main trapping at both the western and eastern ends of the pool is effected by sub-Colony channels filled with shaly and cemented rocks. To the east, pooled oil in the Upper Sand extends at least 1 km northeastward from the mapped channel suggesting that there is a fluid connection through the upper part of the channel fill.

On the Neilburg structural high, interwell variations in elevation of the oil-water contact occur in the McLaren oil pool and in the Sparky and Lloydminster non-commercial accumulations. These interwell variations amount to ±3m to ±4m. The variations are controlled by capillary and wetting properties of the reservoir.

ACKNOWLEDGEMENTS

Financial assistance by the Government of Canada and the Government of Saskatchewan under the Heavy Oil/Fossil Fuel Program is gratefully acknowledged. We acknowledge with thanks the invaluable assistance of Dr. Vasu Nambudiri, Mr. Milt Holter, Ms. Chris Blair, and Ms. Judith Potter.

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POTENTIAL FOR ADDITIONAL HYDROCARBON RECOVERY FROM THE COLORADO AND MONTANA GROUPS (CRETACEOUS) OF SASKATCHEWAN

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Windsor, Ontario N9B 3P4

ABSTRACT

Current hydrocarbon production from shaly sandstones of the dominantly argillaceous Colorado and Montana Groups (Middle Albian to Campanian) in Saskatchewan is restricted to the vicinity of the Fourth Meridian, where (1) largely conventional reservoirs of the Viking Formation yield high-gravity crude oil and gas and (2) mainly unconventional (low-permeability) reservoirs of the Medicine Hat Sandstone and Milk River Formation are exploited for major accumulations of non-associated gas. Gas pools in the Spinney Hill Sandstone, St. Walburg Sandstone, and Belly River Formation (Ribstone Creek Tongue) of west-central Saskatchewan and in the Phillips Sandstone (Second Specks Sandstone) of the southwest are also under development. Initial established reserves of crude oil amounted to 17.507×10^6 m^3, about 4.5% of the provincial total, but the figure for natural gas was $50{,}680.8 \times 10^6$ m^3, which was about 68.4% of the provincial total.

The Colorado-Montana succession is prospective for hydrocarbons, notably non-associated gas, generally at depths of less than 1,000 m in southern Saskatchewan. The main shallow hydrocarbon prospects are: (1) conventional and unconventional oil and gas reservoirs in the Bow Island-Viking sequence of the southwest and the Newcastle-Viking sequence of the southeast; and (2) extensive low-permeability gas reservoirs, occurring throughout the succession in western Saskatchewan. The main targets are widely distributed shaly sandstones, which were laid down in nearshore and shelf settings of an epeiric sea by storm-generated currents and underwent attenuation with concomitant grain-size diminution in a basinward direction. The major structural influences on hydrocarbon accumulations are: (1) northeast-trending regional uplifts; (2) northeast-and northwest-trending linear features delineating juxtaposed basement blocks; (3) solution-generated collapse features associated with the Middle Devonian Prairie Evaporite; and (4) drape folds mimicking paleotopography at the sub-Cretaceous unconformity.

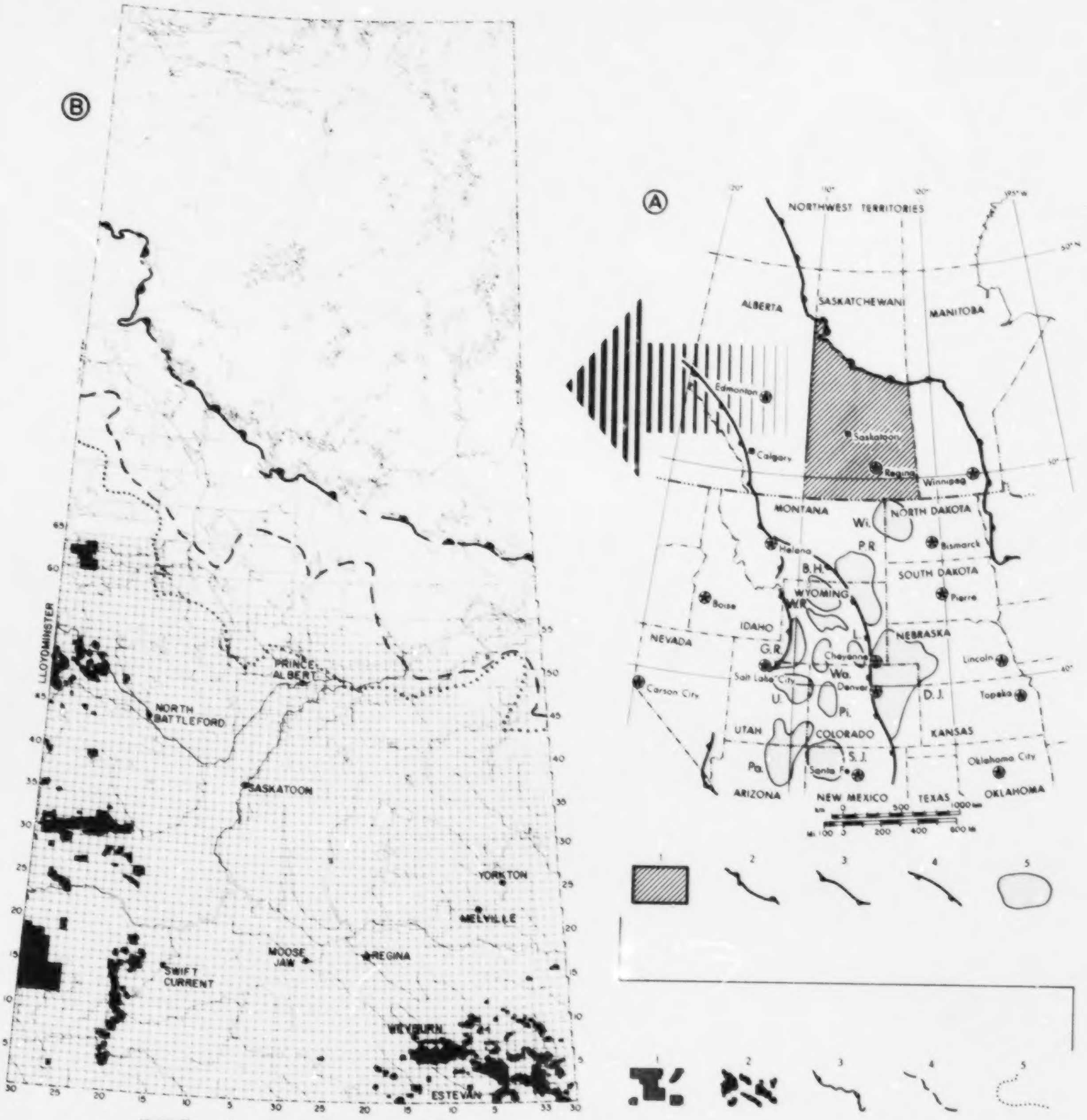
Detailed analysis of reservoir genesis takes on particular significance for the forecasting of porosity-permeability gradients and distribution of different types of heterogeneity in shaly sandstones. It is important for (1) the productionist, seeking to improve recovery efficiency at and near existing production locales, and (2) the explorationist, who must avoid wildcat discoveries, which are "geologic successes and economic failures". Many sandstone bodies exhibit coarsening-upward sequences with alternating layers of sandstone/siltstone and mudstone (bedded shaly sandstones) succeeded by bioturbated shaly sandstones, and are characterized by (1) upward decrease in frequency and thickness of primary heterogeneities (shale breaks) and (2) porosity-permeability gradients of improved reservoir quality paralleling the upward increase in sand size. Well-washed cross-laminated sandstones, overlain by pebbly sandstones and conglomerates, also occur in the upper parts of conventional reservoirs. The occurrence of secondary heterogeneities (cementation barriers) is largely controlled by primary depositional features.

INTRODUCTION

In Saskatchewan, oil and gas are produced from reservoirs ranging in age from Ordovician to Cretaceous. During 1982, production for the province was 8.104×10^6 m^3 of oil with a net value of $1,185,627,621 and $1{,}252.3 \times 10^6$ m^3 of gas valued at $24,257,490 (Saskatchewan Energy and Mines, 1983a, 1983b). The total cumulative production to December 31, 1982, was 290.767×10^6 m^3 of oil and $30{,}958.4 \times 10^6$ m^3 of gas (Saskatchewan Energy and Mines, 1983a). Hydrocarbon production is concentrated in two main areas (Fig. 1): 1) in southeastern Saskatchewan, where mainly Mississippian strata yield light and medium crude oils with associated gas, and 2) at several western locations along the Fourth Meridian, where light, medium, and heavy oils and mostly non-associated gas come from various Mississippian, Jurassic and Cretaceous reservoirs.

Marine sandstone bodies of the Colorado and Montana Groups (middle Albian to Campanian) have yielded commercial quantities of light oil and non-associated gas from depths in the range 229 to 732 m in western Saskatchewan since 1945 (Saskatchewan Energy and Mines, 1983a, 1983b). The largely conventional reservoirs of the Viking Formation in west-central Saskatchewan have accounted for virtually all of the initial established reserves of crude oil in the Colorado-Montana succession, estimated at 17.507×10^6 m^3, or about 4.5% of the provincial total. Initial established reserves of gas, which include non-associated accumulations in the Milk River Formation and the Medicine Hat Sandstone of southwestern Saskatchewan, amounted to $50{,}680.8 \times 10^6$ m^3, or about 68.4% of the provincial total. Indeed, about 76% of Saskatchewan's initial established reserves of non-associated gas have been found in Colorado-Montana strata.

The Colorado and Montana Groups of the entire Western Canadian Sedimentary Basin were described in the complementary studies of Rudkin (1964) and Williams and Burk (1964), and the tectonic evolution of the basin was recently considered by Porter *et al.* (1982). The hydrocarbon potential of the Colorado-Montana succession in Saskatchewan was among the topics considered in papers by Christopher *et al.* (1971, 1973), who provided some of the first descriptions of the principal reservoir strata. The purpose of the present account is to update these earlier surveys of oil and gas prospects in the Colorado and Montana Groups of Saskatchewan with particular reference to recent work by the author on low-permeability reservoirs in the sequence (Simpson, 1982a, 1984, in prep. a and b).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LLOYDMINSTER
NORTH BATTLEFORD
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SASKATOON
YORKTON
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MOOSE JAW
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SWIFT CURRENT
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kilometres 50 0 50 100 150 200 kilometres
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NORTHWEST TERRITORIES
ALBERTA
SASKATCHEWAN
MANITOBA
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Winnipeg
MONTANA
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Fig. 1 - Location map showing southern Saskatchewan in relation to northern Great Plains region.

1A - Principal structural and depositional basins of Cretaceous age in northern Great Plains region. 1 - area of detailed study; 2 - southern edge of Precambrian Shield; 3 - secondary arc of Rocky Mountains; 4 - Big Horn - Front Range series of uplifts; 5 - basin (BH - Big Horn, D-J - Denver-Julesberg, GR - Green River, L - Laramie, Pa - Paradox, Pi - Piceance, PR - Powder River, U - Uinta, Wa - Washakie, Wi - Williston, WR - Wind River).

1B - Distribution of petroleum production in study area. 1 - gas production, 2 - oil production, 3 - southern edge of Precambrian Shield, 4 - northern limit of Lower Colorado strata, 5 - northern limit of Upper Colorado strata.

EXPLORATION AND PRODUCTION HISTORY

Oil and gas reservoirs in the Colorado and Montana Groups of Saskatchewan are listed in Tables 1 and 2 respectively in order of decreasing total cumulative production to December 31, 1982. It is noteworthy that out of a total of 28 pools (8 oil, 20 gas pools), 19 had been found (6 oil, 13 gas pools) by the end of the 1950's, and a decade later the number had risen to 25 pools (7 oil, 18 gas pools). The Hatton Milk River Pool has yielded significant production only since 1973 and is regarded a "1970's discovery" for the purposes of this account, although the occurrence of gas in the unit had been known for at least two decades.

Reservoirs of the Colorado and Montana Groups may be grouped into a limited number of geologically similar types, in order to delineate "plays" as defined by White (1980). The main criteria were depositional history of the reservoir, structural controls and nature of source rocks, and sealing lithologies. The three main Viking plays may be distinguished in west-central Saskatchewan with reference to depositional settings (nearshore/shoreline, proximal-shelf, distal-shelf), described below. The Milk River Formation has yielded two separate plays at Hatton and Liebenthal, whereas the Medicine Hat Formation and Ribstone Creek Tongue (Belly River Formation) are targets in one play each, at Hatton and Whiteside respectively. In addition, a useful study of gas reserves by the Saskatchewan Department of Mineral Resources (1977)

Table 1

PRODUCTION OF CRUDE OIL[1] FROM THE VIKING FORMATION (EARLY CRETACEOUS) IN WEST-CENTRAL SASKATCHEWAN (FROM SASKATCHEWAN ENERGY AND MINES, 1983A)

POOL	DISC DATE	DRIVE	DEPTH (M)	NET PAY (M)	POR (%)	H_2O SAT (%)	PROD TECH	OIP (M^3x10^6)	EST REC (%)	IER (M^3x10^6)	CUM PROD (M^3x10^6)
Dodsland											
Eagle Lake Unit	56	SGD	671	3.02	22.4	45.0	WF	12.758	18.50	2.360	1.659
Gleneath Unit				2.93	21.7	45.0	WF	9.528	24.50	2.334	1.587
Non-Unit				2.44	22.4	45.0	--	36.658	11.50	4.216	1.633
Total								58.944		8.910	4.879
Smiley-Dewar	53	SGD	705	4.42	24.0	45.0	WF	20.082	24.60	4.940	3.860
Eureka											
N Eureka Unit	54	SGD	723	3.32	23.0	42.0	WF	6.705	16.00	1.072	1.010
S Eureka Unit				3.69	23.0	42.0	WF	6.795	19.00	1.292	1.016
Non-Unit				4.14	23.0	42.0	--	1.788	4.00	0.072	0.033
Total								15.288		2.436	2.059
Avon Hill	59	SGD	725	2.44	23.0	45.0	--	6.358	5.60	0.356	0.301
Plato											
Vol. Unit No. 1	68	SGD	644	1.86	22.0	38.0	WF	4.240	6.50	0.276	0.257
Non-Unit				0.85	22.0	38.0	--	0.387	4.50	0.017	0.008
Total								4.627		0.293	0.265
Whiteside											
Unit	53	SGD	724	1.83	24.0	45.0	WF	2.558	8.40	0.215	0.201
Non-Unit				1.83	24.0	45.0	--	0.195	6.50	0.013	0.006
Total								2.753		0.228	0.207
Lucky Hills											
Vol. Unit	59	SGD +GCD	716	3.05	23.0	45.0	--	1.575	4.40	0.069	0.058
Non-Unit				2.74	23.0	45.0	--	1.921	4.00	0.077	0.070
Total								3.496		0.146	0.128
Plato North	78	SGD	705	2.88	23.0	35.0	--	1.135	10.00	0.113	0.010
Miscellaneous											
Viking Sand	--	--	--	4.51	23.0	35.0	--	3.945	2.10	0.083	0.039
Viking Chert	--	--	--	3.51	24.0	35.0	--	0.157	1.20	0.002	0.002

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[1] To December 31, 1982.

Table 2

PRODUCTION OF NATURAL GAS[1] FROM THE COLORADO AND MONTANA GROUPS (CRETACEOUS) IN WESTERN SASKATCHEWAN (FROM SASKATCHEWAN ENERGY AND MINES, 1983A)

TYPE OF RESOURCE	POOL	DISC DATE	PROD HORIZON	DEPTH (M)	NET PAY (M)	POR (%)	IGIP ($M^3 x 10^6$)	IER ($M^3 x 10^6$)	CUM PROD ($M^3 x 10^6$)
Non-assoc. gas	Hatton								
	Unit	53	Med. Hat	477	3.26	21.0	6 871.3	5 222.2	3 741.0
	Agreement Area				2.96	21.0	1 969.2	1 496.6	617.3
	Non-Unit				1.75	21.0	4 618.9	3 510.3	1 524.5
	Total						13 459.4	10 229.1	5 882.8
	Coleville-Smiley								
	Unit	51	Viking	686	2.99	22.5	6 465.7	5 221.1	4 682.9
	Non-Unit				2.44	25.5	58.4	44.4	28.9
	Total						6 524.1	5 265.5	4 711.8
	Hatton								
	Milk River	--	Milk River	335	6.77	16.0	22 405.8	13 835.6	2 481.7
	Milk River - Med. Hat		Milk River + Med. Hat						465.2
	Hoosier								
	Unit	53	Viking	732	3.32	23.0	4 643.4	3 308.4	2 275.4
	Vol. Unit No. 4				2.56	23.0	134.8	96.1	20.0
	Non-Unit				3.81	23.0	51.3	36.6	--
	Total						4 829.5	3 441.1	2 295.4
	Bayhurst								
	Vol. Unit	58	Viking	661	2.71	25.0	2 567.7	1 951.4	1 721.1
	Milton	54	Viking	728	1.89	25.0	1 047.2	845.6	766.9
	Brock								
	Unit	51	Viking	716	2.19	14.5	765.2	567.0	546.0
	Dodsland N								
	Vol. Unit	53	Viking	669	2.01	22.4	874.5	664.6	397.7
	Non-Unit				2.52	22.4	3 429.5	2 606.4	28.5
	Total						4 304.0	3 271.0	426.2
	Whiteside								
	Vol. Unit	62	Ribstone Cr.	229	2.74	35.0	527.4	425.8	384.3
	Greenan	69	Viking	655	1.98	24.6	1 347.9	448.2	274.1
	Totnes								
	Vol. Unit	69	Viking	613	2.71	25.0	465.8	354.0	273.1
	Non-Unit				2.71	25.0	155.2	118.0	1.0
	Total						621.0	472.0	274.1
	Bayhurst W								
	Vol. Unit	68	Viking	696	1.62	30.5	304.7	217.1	165.8
	Liebenthal	74	Milk River	396	2.07	16.0	525.2	324.3	95.4
	Glidden								
	Vol. Unit	53	Viking	694	0.88	21.0	484.0	229.9	73.4
	Unity	45	Viking	503	1.52	21.6	30.3	14.4	14.4
	Brock E	67	Viking	720	0.91	24.0	310.0	103.1	10.2
	Marengo	54	Viking	728	1.89	25.0	323.7	246.0	0.6
	Whiteside W.	56	Viking	724	2.22	22.8	872.4	621.6	0.4
	Miscellaneous								
			Viking				6 940.7	4 890.5	226.4
			Spinney Hill				161.4	116.9	28.8
			Second Specks				1 931.3	1 347.9	12.9
			Milk River				2 313.3	1 428.5	4.5
			Med. Hat				44.1	33.5	4.0
			St. Walburg				356.7	274.0	--
			Ribstone Cr.				74.7	51.3	--
Assoc. gas	Eureka	54	Viking	689	2.01	22.4	12.5	9.5	7.2
	Smiley-Dewar	73	Viking	694	2.29	25.5	15.7	11.9	6.9
	Avon Hill	59	Viking	678	2.13	25.0	10.6	8.1	--

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[1] To December 31, 1982.

recognizes a number of "probable and possible gas areas" in southwestern Saskatchewan on the basis of reserves in the Phillips Sandstone (Second Specks Sandstone) and Milk River Formation. All hydrocarbon occurrences noted above are structural-stratigraphic traps, although diagenetic processes (*cf.* Wilson, 1977) appear to have influenced the entrapment of oil and gas to some degree.

Maturation studies, based on coal rank, and geochemical studies in Alberta by Deroo *et al.* (1977) have shown that oil occurring in the marine sandstone reservoirs of the Colorado and Montana Groups probably originated from source rocks within the Colorado succession. The gas in shallow, low-permeability reservoirs of the Colorado-Montana succession of north-central Montana, approximately equivalent in age to reservoirs of comparable quality in Saskatchewan, is considered to have formed through the breakdown of organic matter in the associated shales by anaerobic bacteria (Rice and Shurr, 1980) on the basis of carbon isotope studies. The gas occurring in low-permeability reservoirs in both Saskatchewan and north-central Montana is dominantly methane.

RESERVOIR STRATA OF THE COLORADO AND MONTANA GROUPS

The marine sandstone and siltstone bodies, referable to the dominantly argillaceous Colorado Group and overlying Montana Group of southern Saskatchewan, exhibit varying degrees of shaliness which reflects lithologic gradation with the enveloping shales and mudstones. The sandstones and siltstones mark stages in the attainment of the graded condition on the shelf areas of an epeiric sea which occupied an asymmetrically subsiding structural basin to the east of the Cordillera (Simpson, 1975, 1979a, 1979b, 1982b). Abundant terrigenous debris was supplied from the rising ancestral Rocky Mountains to a rapidly subsiding western shelf, whereas a relatively quiescent eastern shelf received comparatively minor amounts of siliciclastic debris from the Precambrian Shield. A basin which was the site of mud deposition was located between these shelves. The widespread occurrence of thin graded beds (siliciclastic material, fish-skeletal debris, *Inoceramus* prisms) evidences dispersal by storm-generated suspension currents.

The stratigraphic position of the Colorado-Montana succession within the Mesozoic strata of Saskatchewan and the main lithostratigraphic subdivisions are give in Figure 2. In this section of the paper, the sandstone and siltstone bodies of the Colorado and Montana Groups that are prospective for hydrocarbons in southern Saskatchewan are briefly considered, beginning with the oldest units.

The main sandstone units laid down on the eastern shelf in central Saskatchewan are the Spinney Hill Sandstone, the Flotten Lake Sand, the St. Walburg Sandstone and the Okla Sandstone, listed in order of decreasing age. The units occur in the Lower Cretaceous part of the Colorado Group. In eastern Saskatchewan the Viking-Newcastle succession of the eastern shelf is lithologically similar to the Newcastle Formation of North Dakota and the Ashville Sand of southern Manitoba. These units are largely made up of sandstones and shaly sandstones, which pass into shales and mudstones basinward. The depositional formats of these shelf-to-basin transitions exhibit some degree of lithologic variation, summarized in Table 3. The Spinney Hill Sandstone was first described by Edwards (1960) and the eastern-shelf sandstones of central Saskatchewan were considered by Simpson (1982b, 1984). The Viking-Newcastle succession was examined by Price (1963), Simpson and O'Connell (1979), O'Connell (1981) and Simpson (1984). Papers by Hansen (1955), Wulf (1962), Anderson (1967, 1969) and Reishus (1968) on the equivalent Newcastle Formation of North Dakota contain useful lithologic descriptions, and the Ashville Sand was recently described by Simpson (1983).

Table 3

DEPOSITIONAL FORMATS OF SHELF-TO-BASIN TRANSITION IN THE COLORADO AND MONTANA GROUPS (CRETACEOUS) OF SASKATCHEWAN: SANDSTONES OF EASTERN PROVENANCE

Minor thickness variation and increased shaliness basinward	Spinney Hill Ss.
Thickness highly variable, increasing mainly at expense of underlying shale, with overall basinward thinning	Viking - Newcastle succession, Ashville Sd.
Basinward attenuation	Flotten Lake Sd., St. Walburg Ss., Okla Ss.

Sands on the western shelf were deposited as a relatively coarse-grained regressive-transgressive wedge (Bow Island -Viking succession) which thins northeastwards and eastwards across western Saskatchewan. The stacked multistorey sandstone bodies of the Bow Island Formation give way to a single sandstone, termed the Viking Formation, in which nearshore/shoreline, proximal-shelf and distal-shelf facies have been recognized (Simpson, 1975, 1969b, 1982b). Important papers by Reasoner and Hunt (1955), Jones (1961a, 1961b) and Evans (1970) deal with the Viking Formation of the Dodsland-Hoosier production district of west-central Saskatchewan. The reservoir studies by Koldijk (1976) and Thomas and Oliver (1979) on Viking strata in Alberta reveal lithologic associations similar to those of western Saskatchewan. The Basal Colorado Sand (Cessford Sand) appears to be a tongue of the Bow Island - Viking succession, occurring in southwestern Saskatchewan. The interbedded sandstones and mudstones between the base of the Fish-Scale Marker and the top of the Bow Island - Viking succession in southwestern Saskatchewan are termed the Spikes Sandstone. The Fish-Scale Marker consists of graded sandstones, made up of fish-skeletal debris, alternating with mudstone layers.

The upper part of the Colorado Group is divisible into two main calcareous marker units, the Second (Lower) and First (Upper) White-Speckled Shales, separated by an unnamed noncalcareous shale sequence. In southwestern Saskatchewan, each of these divisions incorporates siliciclastic units consisting of monotonous alternations of sandstones and mudstones, termed the Phillips Sandstone (Second Specks Sandstone), the Bowdoin Sandstone and the Martin Sandy Zone, in order of decreasing age. The calcareous shales and shaly chalks resting on the Phillips Sandstone are the Greenhorn Lime. A prominent reservoir unit, occurring near the top of the Martin Sandy Zone, is the Medicine Hat Sandstone which extends a short distance into southwestern Saskatchewan. Campen (1975), Henry (1979), Nydegger *et al.* (1979), Rice and Shurr (1980) and Rice (1984) described the equivalent Upper Colorado sandstones of northern Montana; Last, Kloepfer Ltd. (1973),

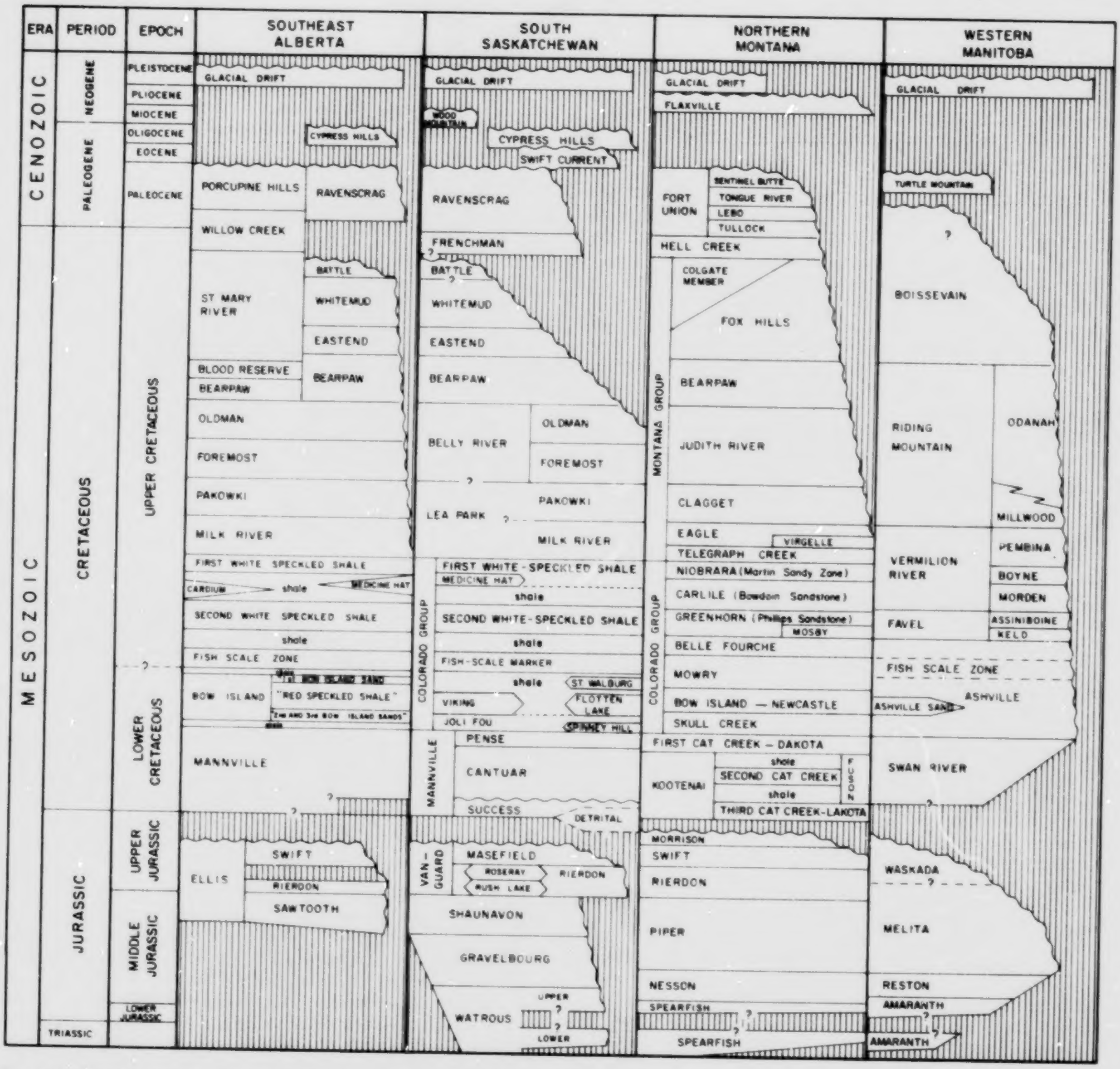

ERA
PERIOD
EPOCH
SOUTHEAST ALBERTA
SOUTH SASKATCHEWAN
NORTHERN MONTANA
WESTERN MANITOBA
CENOZOIC
MESOZOIC
NEOGENE
PALEOGENE
CRETACEOUS
JURASSIC
TRIASSIC
PLEISTOCENE
PLIOCENE
MIOCENE
OLIGOCENE
EOCENE
PALEOCENE
UPPER CRETACEOUS
LOWER CRETACEOUS
UPPER JURASSIC
MIDDLE JURASSIC
LOWER JURASSIC
GLACIAL DRIFT
CYPRESS HILLS
PORCUPINE HILLS
RAVENSCRAG
WILLOW CREEK
BATTLE
ST MARY RIVER
WHITEMUD
EASTEND
BLOOD RESERVE
BEARPAW
OLDMAN
FOREMOST
PAKOWKI
MILK RIVER
FIRST WHITE SPECKLED SHALE
CARDIUM
shale
MEDICINE HAT
SECOND WHITE SPECKLED SHALE
FISH SCALE ZONE
BOW ISLAND
"RED SPECKLED SHALE"
MANNVILLE
SWIFT
ELLIS
RIERDON
SAWTOOTH
WOOD MOUNTAIN
SWIFT CURRENT
FRENCHMAN
BELLY RIVER
LEA PARK
FIRST WHITE-SPECKLED SHALE
SECOND WHITE-SPECKLED SHALE
FISH-SCALE MARKER
ST WALBURG
VIKING
FLOTTEN LAKE
JOLI FOU
SPINNEY HILL
COLORADO GROUP
PENSE
CANTUAR
SUCCESS
DETRITAL
MASEFIELD
ROSERAY
RUSH LAKE
VANGUARD
SHAUNAVON
GRAVELBOURG
WATROUS
UPPER
LOWER
FLAXVILLE
FORT UNION
SENTINEL BUTTE
TONGUE RIVER
LEBO
TULLOCK
HELL CREEK
COLGATE MEMBER
FOX HILLS
MONTANA GROUP
JUDITH RIVER
CLAGGET
EAGLE
VIRGELLE
TELEGRAPH CREEK
NIOBRARA (Martin Sandy Zone)
CARLILE (Bowdoin Sandstone)
GREENHORN (Phillips Sandstone)
MOSBY
BELLE FOURCHE
MOWRY
BOW ISLAND — NEWCASTLE
SKULL CREEK
FIRST CAT CREEK — DAKOTA
KOOTENAI
SECOND CAT CREEK
THIRD CAT CREEK-LAKOTA
FUSON
MORRISON
PIPER
NESSON
SPEARFISH
TURTLE MOUNTAIN
BOISSEVAIN
RIDING MOUNTAIN
ODANAH
MILLWOOD
PEMBINA
VERMILION RIVER
BOYNE
MORDEN
FAVEL
ASSINIBOINE
KELD
ASHVILLE SAND
ASHVILLE
SWAN RIVER
WASKADA
MELITA
RESTON
AMARANTH
?

Fig. 2 - Stratigraphic correlation chart for Mesozoic strata of the northern Williston Basin region.

Last and Kloepfer (1973), the Suffield Evaluation Committee (1974), and Kloepfer and Associates (1978) published accounts of the equivalent strata in southeastern Alberta. Scholle (1977) and Lockridge and Scholle (1978) described gas prospects in calcareous shales and shaly chalks of the U. S. Northern Great Plains region. The Upper Colorado sandstones of southwestern Saskatchewan were considered in a paper by Simpson and Katham (1980), and Kendall and Simpson (1974) described the main lithologic associations of the Medicine Hat Sandstone in the Hatton production district.

The Milk River Formation is a monotonous sequence of shaly sandstones and siltstones, occurring at the base of the Montana Group and exhibiting only minor lithologic variation across a wide area of southwestern Saskatchewan. The marine part of the overlying Montana succession incorporates a prominent eastward-thinning wedge of sandstone, the Belly River Formation. A pulsatory regressive-transgressive pattern of sedimentation is evidenced by several Belly River tongues, alternating in vertical sequence with tongues of the enveloping Lea Park and Bearpaw mudstones and shales; the Ribstone Creek Tongue (Belly River) gas in west-central Saskatchewan. The Milk River Formation occurring in the vicinity of the Fourth Meridian was discussed by Last, Kloepfer Ltd. (1973), Last and Kloepfer (1973), and Kloepfer and Associates (1978). The Suffield Evaluation Committee (1974), Myhr and Meijer-Drees (1976), and Meijer-Drees and Myhr (1981) described the Milk River Formation of southeastern Alberta, while the equivalent strata in southwestern Saskatchewan were the subject of a brief account by Simpson and Singh (1980). The Belly

River Formation (Judith River Formation) of southern Saskatchewan was studied by McLean (1971), and Shouldice (1979) dealt with some Alberta occurrences of the unit.

The sandstone bodies of the western shelf display several different depositional formats of shelf-to-basin transistion which are summarized in Table 4. These formats have played an important role in the localization of hydrocarbon accumulations in conventional and low-permeability reservoirs.

Table 4

DEPOSITIONAL FORMATS OF SHELF-TO-BASIN TRANSITION IN THE COLORADO AND MONTANA GROUPS (CRETACEOUS) OF SASKATCHEWAN: SANDSTONES OF WESTERN PROVENANCE

Basinward replacement of stacked, multistory sandstone bodies by a single unit, thinning basinward	Bow Island - Viking succession
Basinward attenuation	Basal Colorado Ss. Fish-Scale Ss. Medicine Hat Ss. Belly River Tongues
Complex, stepwise basinward attenuation with concomitant age decrease	Phillips Ss. (Second Specks Ss.) Bowdoin Ss.
Minor thickness variation and increased shaliness basinward	Milk River Fm.
Basinward replacement of stacked, multistory sandstone bodies by sandstone tongues	Belly River Fm.

Problems of gas detection in the low-permeability reservoirs of the Colorado and Montana Groups were discussed in papers by Campen (1975), Cannon (1975), Lawrence and Dzurman (1975), Henry (1979) and Kukal (1981), and stimulation techniques applied to gas wells drilled to these strata were considered by Anderson (1974), Campbell and Chmilowski (1975) and Black *et al.* (1980, 1981).

PRINCIPAL CONTROLS OF HYDROCARBON ACCUMULATION

The main lithologic controls of hydrocarbon accumulations in the sandstone and siltstone bodies of the Colorado and Montana Groups in Saskatchewan are:

1) the occurrence of enveloping argillaceous strata associated with the main reservoir units;
2) the basinward attenuation of most sandstone and siltstone bodies;
3) the basinward diminution of grain size, observed in most sandstone and siltstone bodies;
4) the common dominance of upward coarsening of lithologies, making up the main reservoir strata; and
5) the occurrence of concretionary capping lithologies in the sites of best original permeability near the tops of coarsening-upward sequences.

The main structural controls of hydrocarbon accumulation are deep-seated features which have strongly influenced both structure and configuration of depositional systems in the Colorado and Montana Groups and which are themselves complexly inter-related in terms of genesis (Simpson, 1979b, 1982a, 1984):

1) Basement linear features of regional extent are defined by major northeast-trending and subordinate northwest-trending gravity anomalies. Figure 3 shows the distribu-

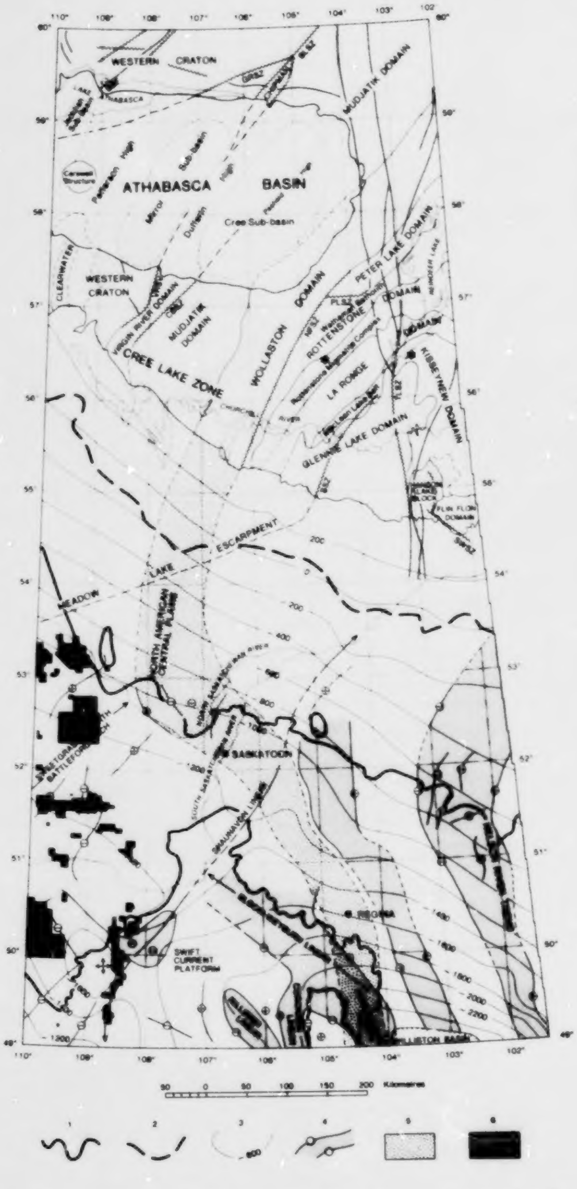

110°
109°
108°
107°
106°
105°
104°
103°
102°
60°
59°
58°
57°
56°
55°
54°
53°
52°
51°
50°
49°
WESTERN CRATON
ATHABASCA
BASIN
Cree Sub-basin
MUDJATIK DOMAIN
PETER LAKE DOMAIN
WESTERN CRATON
CLEARWATER
MUDJATIK DOMAIN
WOLLASTON DOMAIN
ROTTENSTONE DOMAIN
LA RONGE
GLENNIE LAKE DOMAIN
KISSEYNEW DOMAIN
CREE LAKE ZONE
LAKE ESCARPMENT
MEADOW
NORTH AMERICAN CENTRAL PLAINS
SASKATOON
BATTLEFORD
SWIFT CURRENT PLATFORM
WILLISTON BASIN
200
400
600
-1200
-1800
-2000
-2200
50
0
50
100
150
200
Kilometres
1
2
3
4
5
6
-600

Fig. 3 - Basement features and edge of salt in the Prairie Evaporite (Middle Devonian) in relation to commercial hydrocarbon accumulations in Cretaceous strata of southern Saskatchewan.
1 - edge of Prairie Evaporite salt; 2 - northern limit of Colorado (Cretaceous) strata; 3 - structure contours on Precambrian surface (CI = 200 m); 4 - gravity gradient showing positive and negative margins; 5 - conductive geomagnetic anomaly; 6 - oil and gas fields.

tion of oil and gas fields producing from Mesozoic reservoirs, as well as the present (solution) limits of the Middle Devonian Prairie Evaporite according to Holter (1969) and Fuzesy (1982), superimposed on the map of basement features by Macdonald and Broughton (1980). The most important regional feature is the Sweetgrass Arch which restricted dispersal of siliciclastic detritus across the western shelf and currently influences large-scale structure in western Saskatchewan near the Fourth Meridian.

2) Basement linear features of local extent are also defined by northeast- and northwest-trending gravity anomalies, shown in Figure 3. These anomalies are considered to delineate fractures marking the boundaries of juxtaposed basement blocks which have undergone differential movement. Kent (1974) described fractures of comparable scale and with similar trends affecting Phanerozoic strata over a wide area of southern Saskatchewan. Robinson *et al.* (1969) presented evidence for the existence of similar features in south-central Alberta. An example in southwestern Saskatchewan is provided by the gravity anomalies which delineate the northern and eastern limits of the Medicine Hat and Milk River gas Pools at Hatton and appear to mark the boundaries of an elevated basement block.

3) Solution features associated with the Prairie Evaporite (Middle Devonian) reflect the influence of deep-seated northeasterly and northwesterly trends. The solution edge of the Prairie Evaporite salt according to Holter (1969) and Fuzesy (1982), as well as linear solution features with dominantly northwesterly trends and sub-circular solution sinks taken from the publications of Holter (1969), Kent (1974), Simpson and Dennison (1975), and Fuzesy (1982), are shown in Figure 4. The relationship between solution-generated collapse features and tectonism in both the cratonic interior and the continental margin was discussed in a recent paper by Simpson (1978).

4) The paleotopography of the sub-Cretaceous unconformity was to a large extent controlled by basement structure and solution-generated collapse features (Christopher *et al.*, 1971), resulting in marked variations in elevation and downcutting along erosional scarps into Jurassic, Mississippian and Devonian units (Fig. 5). The erosional edges of the Jurassic and Mississippian strata shown in Figure 5 are from Springer *et al.* (1964) and the edges of Devonian units are taken from Kent (1968). Irregular folds mimicking the pre-Cretaceous paleotopography were produced by compaction of the dominantly argillaceous Colorado and Montana Groups (Christopher *et al.*, 1971). Drape folding has also taken place over reactivated basement features. In Figure 5, hydrocarbon production from nearshore (Bayhurst, Bayhurst West pools), proximal-shelf (Dodsland-Hoosier production trend) and distal-shelf (Unity Pool) deposits of the Viking Formation is seen to be localized above parts of the erosional edges of Jurassic, Mississippian and Devonian (Upper Member of the Birdbear Formation) strata respectively. Compaction-formed structures appear to have influenced the development of some depositional systems in the marine Cretaceous succession (Christopher *et al.*, 1971; Simpson, 1982b, 1983). It is therefore possible that the axes of Dina valley-fill deposits shown in Figure 6 may be useful indicators of sandstone-body trends in the Colorado-Montana sequence. The Dina valley-fill trends shown in Figure 6 are taken from Christopher (1974, 1980) and the salt-solution features from Fuzesy (1982).

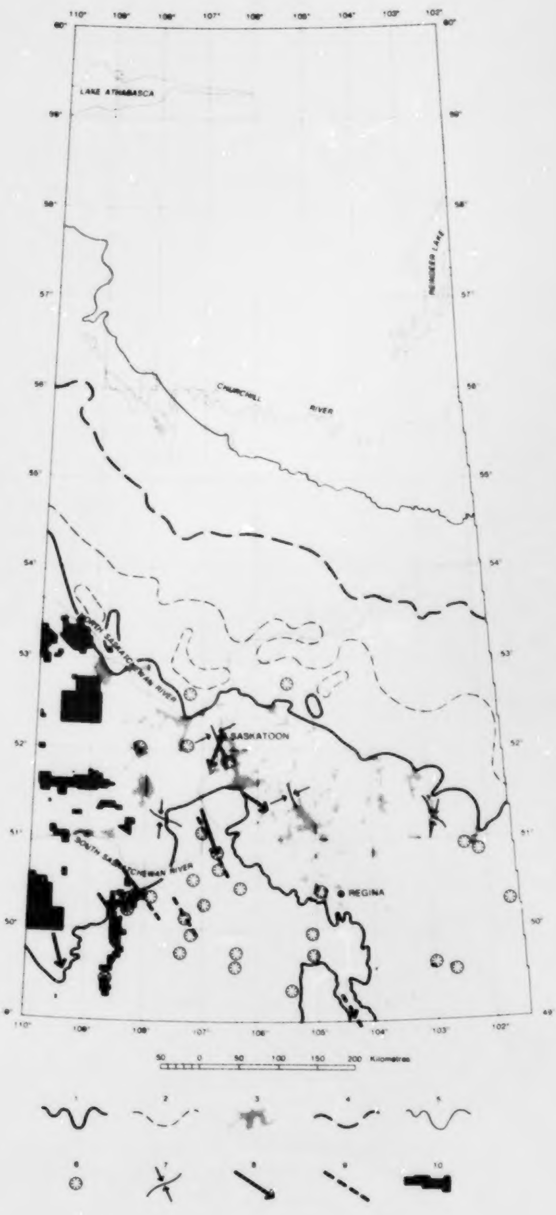


Fig. 4 - Solution-generated collapse features associated with the Prairie Evaporite (Middle Devonian) in relation to commercial hydrocarbon accumulations in Cretaceous strata of southern Saskatchewan.

1 - edge of Prairie Evaporite salt, 2 - edge of Prairie Evaporite anhydrite, 3 - local salt solution (seismic anomaly), 4 - northern limit of Colorado (Cretaceous) strata, 5 -southern perimeter of Precambrain Shield, 6 - sinks and large-scale circular structures, 7 - linear solution features, 8 - trend to known multistage salt-solution structures, 9 - major seismic positive elements, 10 - oil and gas fields.

CHARACTERIZATION OF THE MAIN RESERVOIRS

SEQUENCE ELEMENTS

In a siliciclastic reservoir, effective (interconnected) porosity and related three-dimensional variation in permeability are to

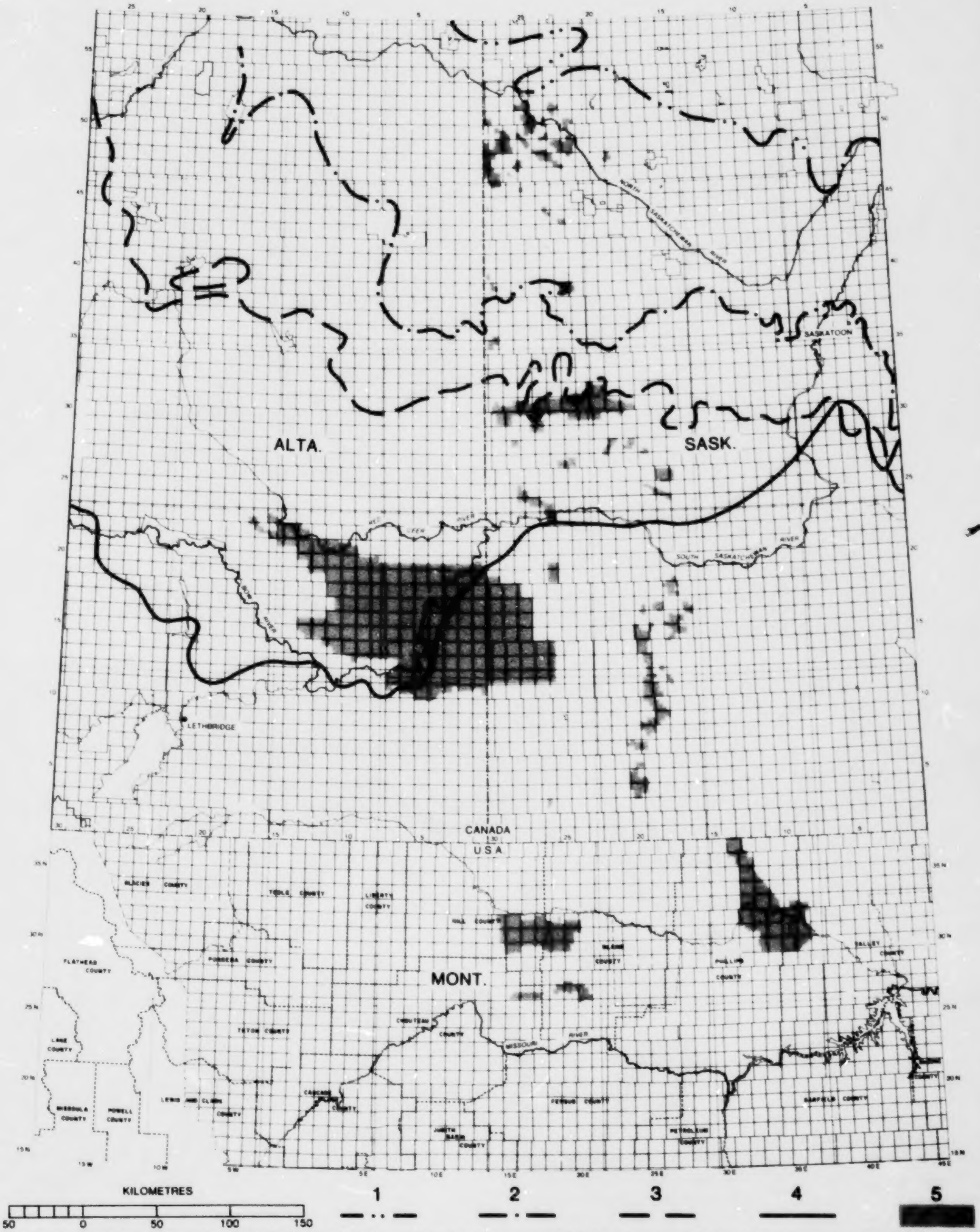

SASKATOON
ALTA.
SASK.
NORTH SASKATCHEWAN RIVER
RED DEER RIVER
SOUTH SASKATCHEWAN RIVER
BOW RIVER
LETHBRIDGE
CANADA
U.S.A.
MONT.
MISSOURI RIVER
KILOMETRES
50
0
50
100
150
1
2
3
4
5

Fig. 5 - Erosional edges of Devonian, Mississippian and Jurassic strata in relation to commercial hydrocarbon accumulations in Cretaceous strata of southern Saskatchewan. 1 - edge of Saskatoon Member (Duperow Formation, Devonian), 2 - edge of Upper Member of Birdbear Formation (Devonian), 3 - edge of Mississippian strata, 4 - edge of Jurassic strata, 5 - oil and gas fields.

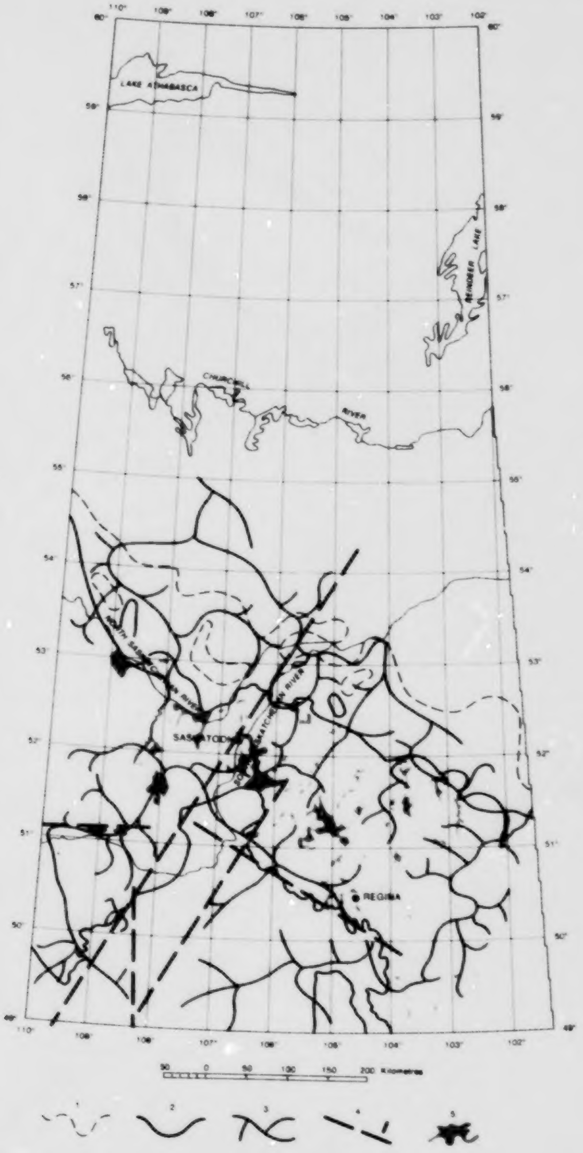


Fig. 6 - Solution-generated collapse features associated with the Prairie Evaporite (Middle Devonian) and axes of Dina (Early Cretaceous) valley fill. 1 -edge of Prairie Evaporite anhydrite, 2 - edge of Prairie Evaporite salt, 3 - axis of Dina valley fill, 4 - structural linears, 5 - local salt solution (seismic anomaly).

a large extent controlled by primary (depositional) arrangements of grain aggregates. Thus, primary sedimentary structures provide important clues about permeability anisotropy in reservoir strata (Pettijohn *et al.*, 1973). Continuous shale layers are the most conspicuous primary reservoir heterogeneities (inhomogeneities), which confine fluid flow to conduits of "stratified permeability" with little or no vertical cross-flow (Zeito, 1965; Verrien *et al.*, 1967; Weber, 1982). Sets and co-sets of cross-strata with preferred orientation strongly influence anisotropic horizontal permeability (Pettijohn *et al.*, 1973), although fine-grained ripple-bedded sandstones with shale laminations have also been shown to constitute barriers to the movement of fluids (Hrabar and Potter, 1969). Strongly cemented concretionary layers commonly form secondary reservoir heterogeneities which originated where primary sedimentary structures provided pathways of easy movement for mineral-enriched solutions (*e.g.*, Simpson, 1980). Thus the study of the primary sedimentary structures of reservoir strata has considerable significance for the development of hydrocarbon reserves (Groult *et al.*, 1966; Polasek and Hutchinson, 1967; Verrien *et al.*, 1967), in particular with regard to enhanced-recovery operations (*e.g.*, Weber *et al.*, 1978). The integration of sedimentological and engineering data has great potential to increase the recovery efficiency of oil and gas reservoirs (Hewitt, 1966; Harris and Hewitt, 1967).

The gradational relationships between fine-grained lithologies which make up the marine Cretaceous strata of Saskatchewan present certain difficulties with regard to their systematic description. These difficulties are to some extent alleviated when conventional rock classifications are augmented by use of the scheme of sequence elements summarized in Table 5. These associations of gross lithologies and sedimentary structures were first recognized in the Lower Colorado strata of west-central Saskatchewan (Simpson, 1971, 1975, 1982b), and were later described from the entire marine Cretaceous succession of the province (Simpson, 1979a, 1980, 1982a). A particular advantage to be gained from use of the scheme lies in its ready application to detailed reservoir studies, in that it places emphasis on abundance and degree of continuity of shale breaks. It is noteworthy that two main types of shaly sandstone are recognized: 1) bedded shaly sandstones (type-II elements) characterized by regular alternation of sandstones and shales; and 2) bioturbated shaly sandstones (type-III elements) in which discontinuous mudstone partings are closely spaced and abundant.

The relationships between lithologic associations (expressed as sequence elements), depositional environments and generalized fluid-flow characteristics of the Viking Formation in west-central Saskatchewan are presented in Table 6.

RESERVOIR HETEROGENEITIES

The ultimate recovery of hydrocarbons from a reservoir is strongly affected by three levels of heterogeneity (Alpay, 1972) summarized in Table 7:

Table 7

HIERARCHY OF RESERVOIR HETEROGENEITIES IN SANDSTONE BODIES OF THE COLORADO AND MONTANA GROUPS (CRETACEOUS) IN SASKATCHEWAN (AFTER ALPAY, 1972)

HETEROGENEITIES		
MICROSCOPIC	MACROSCOPIC	MEGASCOPIC
On Scale of Individual Pores	Lithologic Variation Between Wells	Lithologic Variation on Scale of Field or Regional in Extent
A. pore-size distribution	A. stratification characteristics	A. stratigraphic framework of reservoir
B. pore geometry	B. porosity-permeability characteristics	B. structural framework of reservoir
C. pore occlusion		C. hyperpermeability (oriented natural fracture systems)
D. dead-end pore space		
← PRODUCTIONIST →		← EXPLORATIONIST →
UTILITY		

Table 5

SEQUENCE ELEMENTS, BASED ON GROSS LITHOLOGIC ASSOCIATIONS AND LAYER PROPERTIES, IN CORES OF COLORADO GROUP (CRETACEOUS) IN SASKATCHEWAN (AFTER SIMPSON, 1971)

SEQUENCE ELEMENT[1]	SUB-ELEMENT[2]	REMARKS
V conglomeratic element	(c) pebbly mudstone	coarse traction load and lag concentrates of nodular and broken concretionary material
	(b) conglomerate	
	(a) pebbly sandstone	
IV sandstone element	(e) sandstone with dune-scale cross-lamination	continuous mudstone layers frequently intercalated; best original porosity usually plugged by cement (siderite, calcite, pyrite)
	(d) sandstone with horizontal lamination	
	(c) sandstone with trough cross-lamination	
	(b) sandstone with ripple-drift cross-lamination	
	(a) flaser-bedded sandstone	
III muddy sandstone-siltstone element	(c) bioturbated sandstone	bioturbated shaly sandstones: continuity of mudstone layers mostly disrupted by biogenic reworking
	(b) bioturbated muddy sandstone	
	(a) bioturbated muddy siltstone	
II siltstone-sandstone element	(d) wavy-bedded, composite layers of sandstone, siltstone and mudstone	bedded shaly sandstones: coquinoidal layers of pelecypod and fish-skeletal debris common
	(c) wavy-bedded simple layers of sandstone, siltstone and mudstone	
	(b) alternating mudstone and sandstone/siltstone with low-angle, planar cross-lamination	
	(a) lenticular-bedded siltstone and sandstone in mudstone	
I mudstone element	(c) subordinate siltstone and sandstone in lenses and scarce continuous layers	shale breaks: frequently incorporate coquinoidal layers, bentonitic mudstones, siderite and calcite concretions, nodular phosphorite
	(b) subordinate siltstone and sandstone in flattened lenses	
	(a) structureless mudstone	

[1] Arbitrary lower limit of thickness set at 0.3 m for convenience in core description.

[2] No preferred vertical order of occurrence implied within sequence elements IV and V.

1) Microscopic heterogeneities occur as pore-to-pore variations in the texture of a reservoir unit. They are related to the pore-size distribution, pore geometry, dead-end pore space and types of pore occlusion which influence the irreducible water saturation and residual oil retained in a reservoir under development. Types of pore occlusion with significance for exploitation of reservoirs in the marine Cretaceous sandstones of Saskatchewan include coarse-grained calcite cements displaying poikilitic texture, and widespread occurrence of kaolinite, notably in the lower parts of multistory, sandstone bodies. On the other hand kaolinite-poor sandstones in the Bow Island

Table 6
SEQUENCE ELEMENTS, DEPOSITIONAL ENVIRONMENTS AND GENERALIZED FLUID-FLOW CHARACTERISTICS, VIKING FORMATION, WEST-CENTRAL SASKATCHEWAN

LOCATION IN MARINE BASIN SEQUENCE ELEMENT	NEARSHORE DEPOSITS	PROXIMAL SHELF DEPOSITS	DISTAL SHELF DEPOSITS
V good reservoir quality, incorporate strongly indurated layers (calcite, siderite, pyrite cements) and mudstone intercalations as reservoir heterogeneities	scarce; material coarser than sand usually concentrated in thin layers making up minor proportions of other elements	abundant; highest permeabilities (several hundred md) in diamictites belonging to lower parts of clinobeds[2], primary and secondary heterogeneities very numerous	absent; material coarser than sand occurs as scattered clasts or as thin layers within other elements
IV good reservoir quality; strongly indurated layers (calcite, siderite cements) mudstone intercalations, ripple-drift cross-laminated sandstones are permeability barriers	abundant, planar foresets give rise to highest horizontal permeabilities (several hundred md to >2 D) especially near top of sequence[1]; porosities in range 25 to 35 per cent; primary heterogeneities more numerous downward; secondary heterogeneities at top of sequence	scarce; occur in upper part of sequence where present	very scarce, though well sorted fine-grained sandstone layers may make up minor proportions of type-II and-III elements
III reservoir quality good to poor; strongly indurated parts (calcite, siderite, pyrite cements) and continuous mudstone intercalations are permeability barriers	relatively scarce; usually found near base of sequence, proportion of mudstone intercalations increases downward	abundant; variable horizontal permeability (<0.01md to several hundred md); porosities in range 20 to 30 per cent form coarsening-upward units in upper parts of clinobeds[3], primary heterogeneities in lower parts; secondary heterogeneities near element tops	common, high mud content; variable but usually low horizontal permeability (<0.01 md to several tens of md)[4] porosities in range 15 to 25 per cent
II reservoir quality fairly good to poor; incorporate stratiform and nodular pyrite concretions, sideritic concretions and contain numerous mudstone layers	scarce, occur near base of sequence	abundant; variable horizontal permeability (<0.01md to several hundred md); porosities in range 15 to 25 per cent; form lower parts of clinobeds[3]; downward increase in mud content	common in lower part of sequence[4]
I reservoir heterogeneities, seat and cap rocks	very scarce	common; occur near top of succession and as intercalations	abundant; occur near top of succession and as intercalations

---

[1] main producing lithology of Bayhurst natural gas field

[2] Smiley-Dewar "Viking chert" oil reservoir

[3] crude oil and natural gas reservoirs of the Dodsland-Hoosier "Viking sand" production trend, Brock, Glidden, Greenan, Plato, Totnes

[4] Unity natural gas reservoir

-Viking succession may reflect the presence of hydrocarbons which inhibited the alteration of feldspar and mica grains by migrating pore waters (Simpson, 1980).

2) Macroscopic heterogeneities are defined by textural variation within a sequence of reservoir strata and are correlated between adjacent wells. Most important among the related stratification characteristics in the sandstone reservoirs of the Colorado and Montana Groups is the dominant upward coarsening of lithologies and of associated systematic arrangements of sequence elements which typify the deposits of the western shelf. Pinchouts of reservoir lithologies, primary heterogeneities (shale breaks) and secondary heterogeneities (cementation barriers), as well as the related compartmentalization of reservoirs, are the most prominent features at this scale of investigation. The main permeability characteristics are anisotropy, which includes improved vertical (relative to the horizontal) permeability in the well-washed sandstones of nearshore/shoreline Viking strata, and gradients of upward-increasing porosity and permeability in many reservoirs under development.

3) Megascopic heterogeneities characterize major lithostratigraphic units, which incorporate reservoir strata and are recognizable on a local (fieldwide) or regional scale. The lithologic and structural controls of hydrocarbon accumulations outlined in the preceding section strongly influence reservoir geometry and affect fluid flow at this scale. Also noteworthy are the clinobeds delimited by bentonite and bentonitic mudstones in the Viking Formation of the Dodsland-Hoosier district (Evans, 1970; Simpson, 1975, 1982b), and associated reservoir separation and porosity pinchouts.

The suggestion is made in Table 7 that the main significance of the macroscopic through megascopic range of heterogeneity for the definition of drilling targets is for the planning of exploration strategy, whereas the microscopic through macroscopic range lends itself to applications which are dominantly oriented towards improvement of production. As units with relatively poor reservoir quality become increasingly attractive as exploration targets, production strategy may be expected to assume greater importance in exploration philosophy and operators seek to avoid what Hardin and Mygdal (1968) have described as "a geologic success that is an economic failure." For example, exploitation of oil reserves in shaly sandstone reservoirs will increasingly involve the use of enhanced-recovery techniques from the outset of production and the development of shallow low-pressure gas accumulations from low-permeability reservoirs will involve the drilling of many wells with close spacing.

VIKING FORMATION

The Viking Formation of west-central Saskatchewan consists of shaly sandstones and conglomerates in dominantly coarsening-upward sequences, reflecting sedimentation on the shallow western shelf of an epeiric sea (Simpson, 1982b). The unit decreases markedly in thickness and concomitant grain size in a northeasterly (basinward) direction. The deposits of nearshore proximal-shelf and distal-shelf settings were recognized on the basis of gross lithology and associations of sedimentary structures, and distinctive reservoir characteristics were shown to be associated with each of the generalized depositional environments (Table 6).

The nearshore deposits are characterized by type-IV elements comprising widespread well-washed sandstones in planar foresets. Primary reservoir heterogeneities (shale breaks) occur with increased frequency downwards and secondary heterogeneities (cementation barriers) are commonly found at the top of the unit. Porosities are generally in the range 25 to 35%, and maximum horizontal permeabilities are from a few hundred millidarcies to nearby 2000 millidarcies. This facies is represented in the Viking reservoir strata of the Bayhurst Pool (Figs. 7A and 7B). The Bayhurst and Bayhurst West Pools have initial established reserves of non-associated gas amounting to $2,168.5 \times 10^6$ m^3. These pools occur in structures associated with drape folds in the marine Cretaceous succession, in part coincident with the northern erosional limit of Jurassic strata at the sub-Cretaceous unconformity.

The proximal-shelf deposits are largely made up of bedded shaly sandstones (type-II elements) succeeded upwards by bioturbated shaly sandstone (type-III elements), with subordinate conglomerates being common near the top of the unit. Primary reservoir heterogeneities are abundant in the lower part of the sequence and secondary heterogeneities are found near the top. The proximal-shelf strata exhibit porosities of 20 to 30% in the bioturbated deposits, whereas values of 15 to 25% are typical for the bedded shaly sandstones. Permeabilities of up to several hundred millidarcies characterize these deposits.

The proximal-shelf deposits account for initial established reserves of non-associated gas amounting to $20,402.5 \times 10^6$ m^3. The Coleville-Smiley, Dodsland North and Hoosier Pools, contain 63.6% of these reserves, and are located along the Dodsland-Hoosier production trend which is characterized by drape folds in the Colorado succession coincident with the northern erosional edge of Mississippian strata at the sub-Cretaceous unconformity. The proximal-shelf facies contains all of the Viking high-gravity crude oil discovered in west-central Saskatchewan, and initial established reserves of associated gas are 29.5×10^6 m^3. The Smiley-Dewar Pool (Figs. 8A and 8B) and the Eureka Pool (Figs. 9A and 9B) obtain production of crude oil from linear downwarps which are coincident with valleys in the erosional edge of Mississippian strata at the sub-Cretaceous unconformity. The occurrence of pebbly sandstones and conglomerates (Viking Chert) at the base of the Viking succession at these locations adds support to the view that drape folding was locally, at least in part, syndepositional.

The distal-shelf strata of the Viking Formation are largely made up of bedded and bioturbated shaly sandstones (type-II and type-III elements) with porosities of 15 to 25% and permeabilities of up to several tens of millidarcies. The only hydrocarbon production from this facies is at Unity (Figs. 10A and 10B) where initial established reserves were 14.4×10^6 m^3. The Unity Pool is associated with structure in the Colorado sequence, and coincides with the northern erosional edge of the Upper Member of the Birdbear Formation (Devonian) at the sub-Cretaceous unconformity.

MEDICINE HAT SANDSTONE

The Medicine Hat Sandstone comprises about 13.7 m of very fine- and fine-grained muddy sandstones and intercalated sandstones and shales. The unit is made up of bedded shaly sandstones (type-II elements) commonly succeeded by bioturbated shaly sandstones (type-III elements) in dominantly coarsening-upward sequences. Primary reservoir

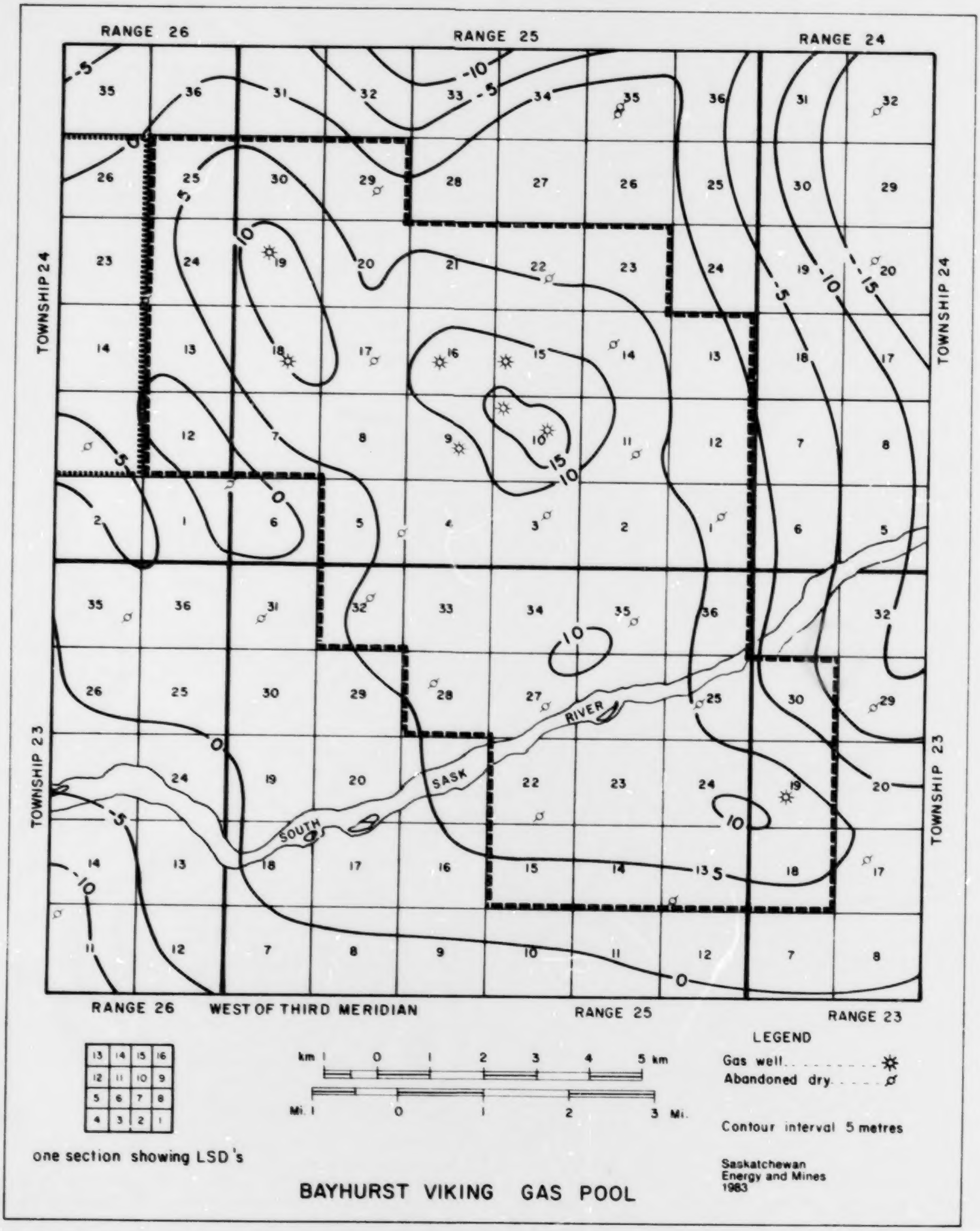

RANGE 26
RANGE 25
RANGE 24
TOWNSHIP 24
TOWNSHIP 23
SOUTH SASK RIVER
RANGE 26
WEST OF THIRD MERIDIAN
RANGE 25
RANGE 23
LEGEND
Gas well
Abandoned dry
km 1 0 1 2 3 4 5 km
Mi. 1 0 1 2 3 Mi.
Contour interval 5 metres
one section showing LSD's
BAYHURST VIKING GAS POOL
Saskatchewan Energy and Mines 1983

Fig. 7A - Structure contours on the Viking Sand of the Bayhurst Pool, west-central Saskatchewan.

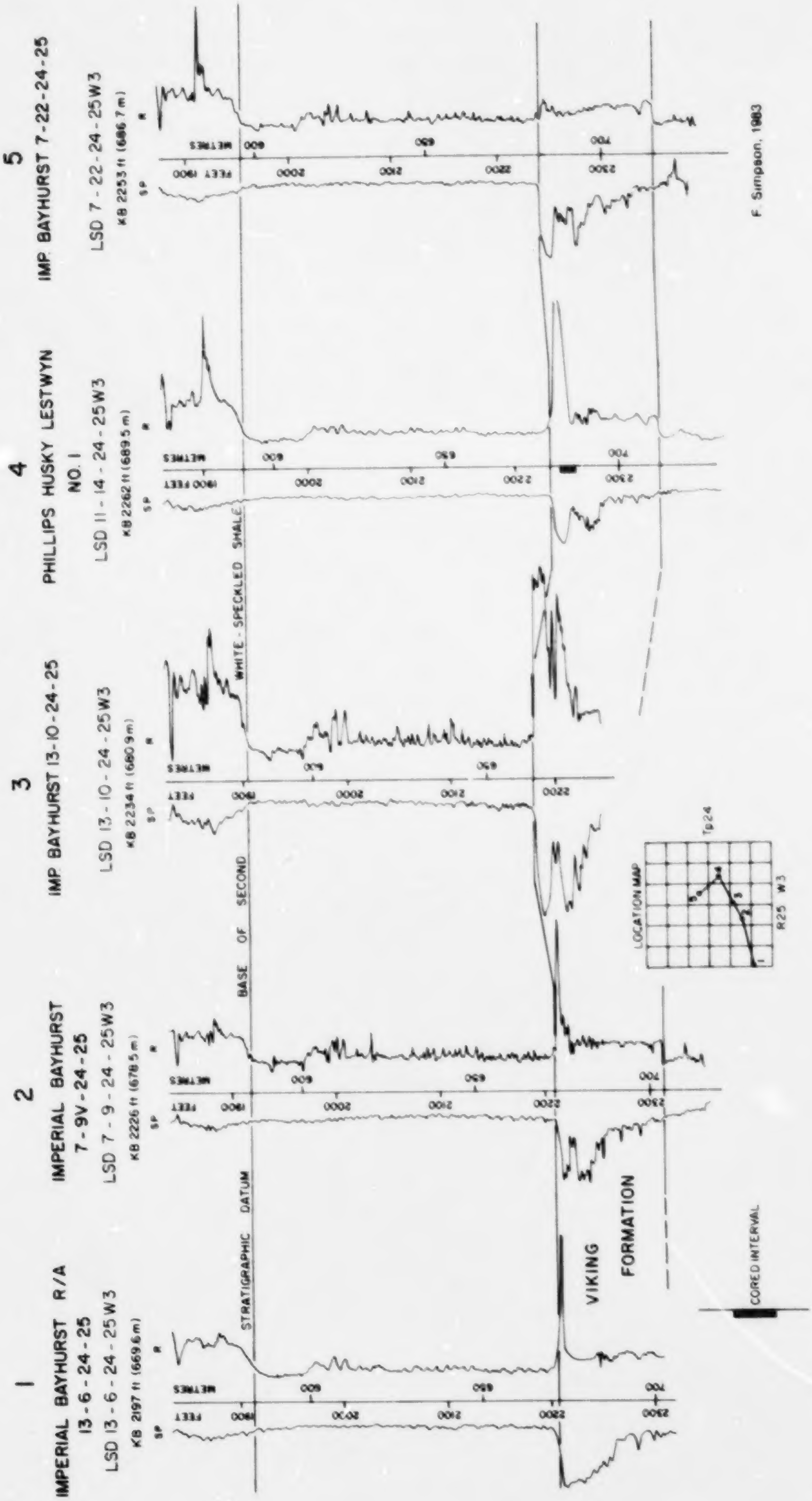

1
IMPERIAL BAYHURST R/A
13-6-24-25
LSD 13-6-24-25W3
KB 2197 ft (669.6 m)
2
IMPERIAL BAYHURST
7-9V-24-25
LSD 7-9-24-25W3
KB 2226 ft (678.5 m)
3
IMP. BAYHURST 13-10-24-25
LSD 13-10-24-25W3
KB 2234 ft (680.9 m)
4
PHILLIPS HUSKY LESTWYN
NO. 1
LSD 11-14-24-25W3
KB 2262 ft (689.5 m)
5
IMP. BAYHURST 7-22-24-25
LSD 7-22-24-25W3
KB 2253 ft (686.7 m)
SP
R
FEET
METRES
1900
2000
2100
2200
2300
600
650
700
STRATIGRAPHIC DATUM
BASE OF SECOND WHITE-SPECKLED SHALE
VIKING FORMATION
CORED INTERVAL
LOCATION MAP
Tp24
R25 W3
F. Simpson, 1983

Fig. 7B - Stratigraphic cross-section of the Bayhurst Viking Pool, west-central Saskatchewan.

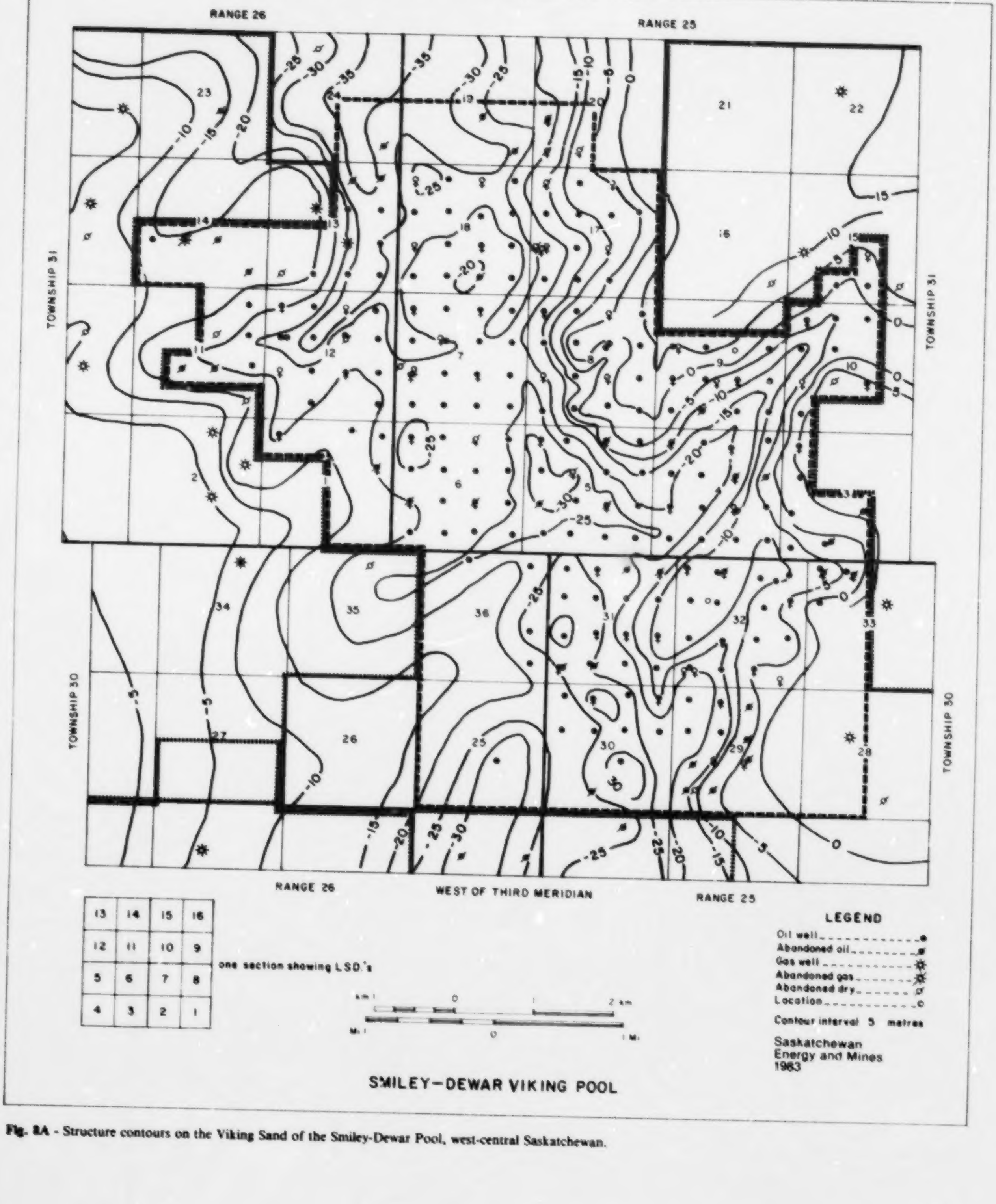

RANGE 26
RANGE 25
TOWNSHIP 31
TOWNSHIP 30
RANGE 26
WEST OF THIRD MERIDIAN
RANGE 25
13 14 15 16
12 11 10 9
5 6 7 8
4 3 2 1
one section showing L.S.D.'s
km 1 0 1 2 km
Mi 1 0 1 Mi
LEGEND
Oil well ●
Abandoned oil
Gas well ☼
Abandoned gas
Abandoned dry
Location ○
Contour interval 5 metres
Saskatchewan Energy and Mines 1983
SMILEY—DEWAR VIKING POOL

Fig. 8A - Structure contours on the Viking Sand of the Smiley-Dewar Pool, west-central Saskatchewan.

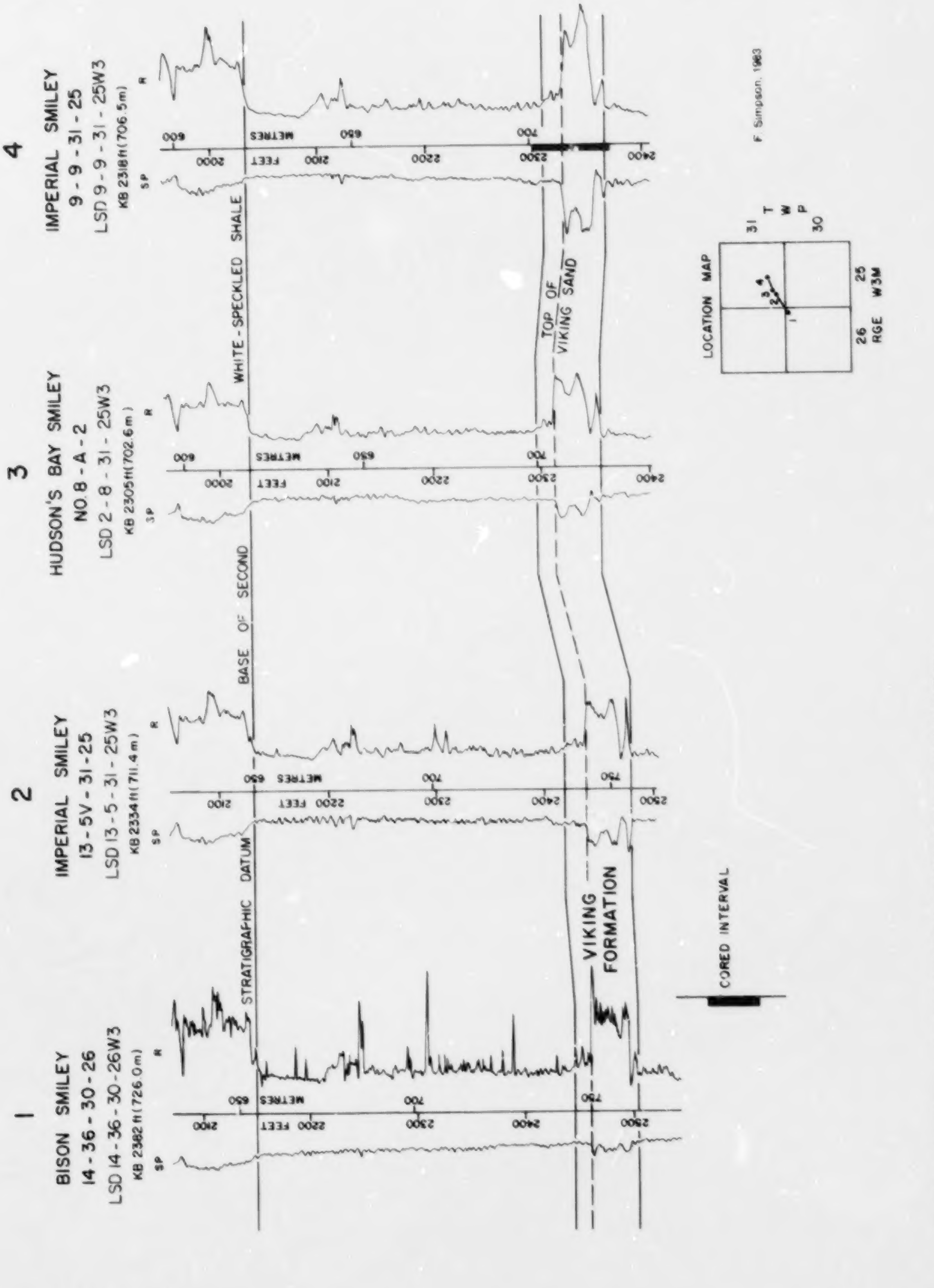

1
BISON SMILEY
14-36-30-26
LSD 14-36-30-26W3
KB 2382 ft (726.0 m)
2
IMPERIAL SMILEY
13-5V-31-25
LSD 13-5-31-25W3
KB 2334 ft (711.4 m)
3
HUDSON'S BAY SMILEY
NO. 8-A-2
LSD 2-8-31-25W3
KB 2305 ft (702.6 m)
4
IMPERIAL SMILEY
9-9-31-25
LSD 9-9-31-25W3
KB 2318 ft (706.5 m)
SP
R
FEET
METRES
STRATIGRAPHIC DATUM
BASE OF SECOND
WHITE-SPECKLED SHALE
TOP OF VIKING SAND
VIKING FORMATION
CORED INTERVAL
LOCATION MAP
31
30
TWP
26
25
RGE W3M
F. Simpson, 1983

Fig. 88 - Stratigraphic cross-section across the Smiley-Dewar Viking Pool, west-central Saskatchewan.

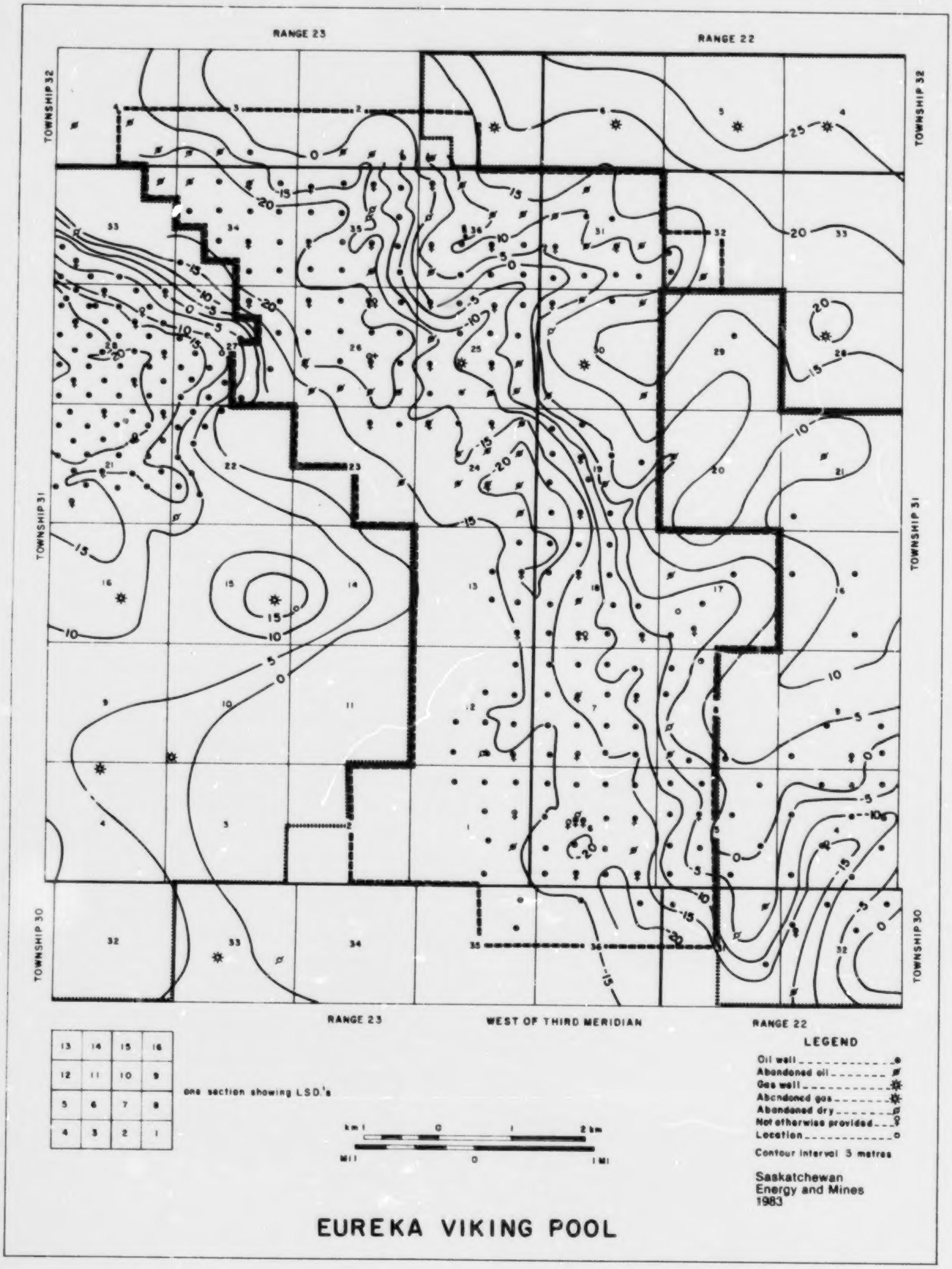

RANGE 23
RANGE 22
TOWNSHIP 32
TOWNSHIP 31
TOWNSHIP 30
RANGE 23
WEST OF THIRD MERIDIAN
RANGE 22
one section showing LSD.'s
km 1 0 1 2 km
MI 1 0 1 MI
LEGEND
Oil well
Abandoned oil
Gas well
Abandoned gas
Abandoned dry
Not otherwise provided
Location
Contour interval 5 metres
Saskatchewan Energy and Mines 1983
EUREKA VIKING POOL

Fig. 9A - Structure contours on the Viking Sand of the Eureka Pool, west-central Saskatchewan.

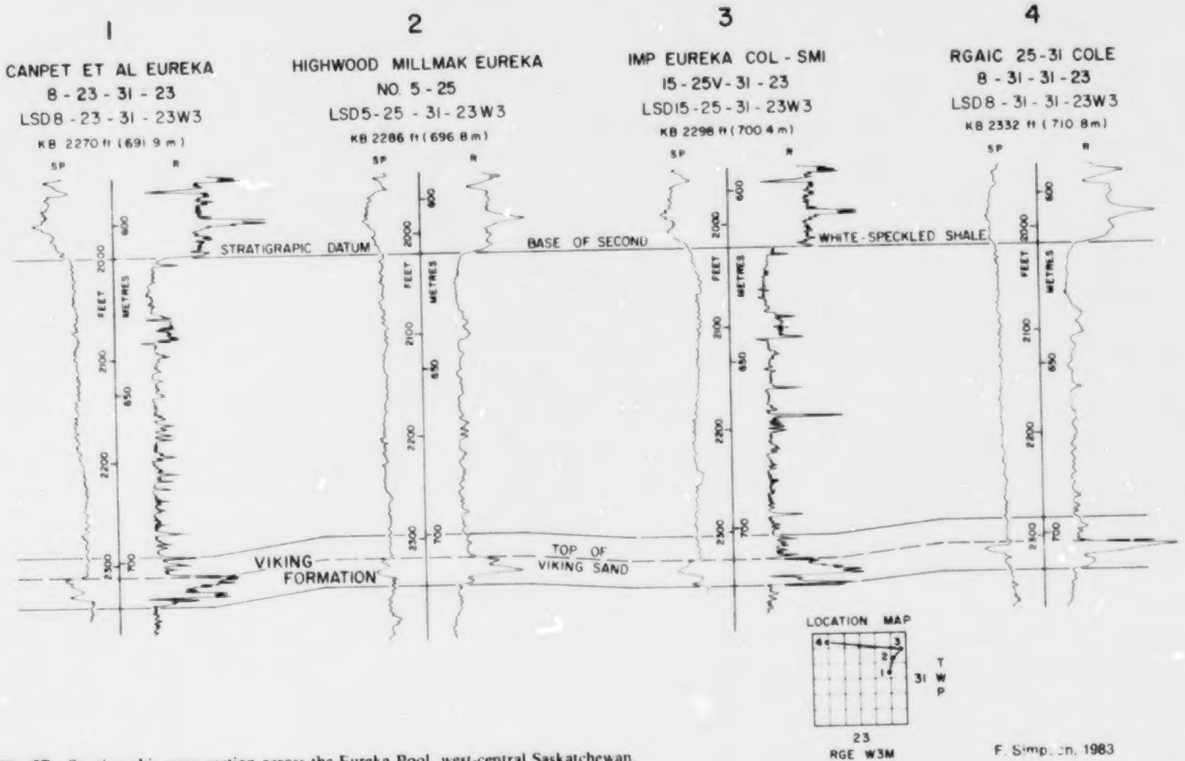

1
CANPET ET AL EUREKA
8 - 23 - 31 - 23
LSD8 - 23 - 31 - 23W3
KB 2270 ft (691 9 m)
2
HIGHWOOD MILLMAK EUREKA
NO. 5 - 25
LSD5 - 25 - 31 - 23W3
KB 2286 ft (696 8 m)
3
IMP EUREKA COL - SMI
15 - 25V - 31 - 23
LSD15 - 25 - 31 - 23W3
KB 2298 ft (700 4 m)
4
RGAIC 25-31 COLE
8 - 31 - 31 - 23
LSD8 - 31 - 31 - 23W3
KB 2332 ft (710 8m)
SP
R
FEET
METRES
STRATIGRAPIC DATUM
BASE OF SECOND
WHITE - SPECKLED SHALE
VIKING FORMATION
TOP OF VIKING SAND
LOCATION MAP
31 TWP
23 RGE W3M

Fig. 9B - Stratigraphic cross-section across the Eureka Pool, west-central Saskatchewan.

F. Simpson, 1983

heterogeneities tend to decrease in frequency and thickness upwards. Secondary heterogeneities are calcareous concretionary layers occurring near the top of the unit. Porosities vary from 5 to 30% to give an average of 16%, and permeabilities range from 0.1 to more than 250 millidarcies. The initial established gas reserves in the Medicine Hat Sandstone at the Hatton Pool (Figs. 11A and 11B) were 10,262.6 × 10⁶ m³ or 20.4% of the total for the Colorado and Montana Groups of Saskatchewan.

MILK RIVER FORMATION

The Milk River Formation of southwestern Saskatchewan consists of 120 m of bioturbated sandstones and siltstones (type-III elements) which incorporate scarce sandstone lenses and layers of concretionary siderite. Porosities are generally less than 20% and permeabilities are commonly less than one millidarcy. The unit was deposited in a shallow marine-shelf setting. The Milk River Formation of the Hatton (Figs. 11B and 11C) and Liebenthal districts contained initial established gas reserves of 15,264.1 × 10⁶ m³ or 30.3% of the initial established reserves in the marine Cretaceous sandstones of Saskatchewan.

RIBSTONE CREEK TONGUE (BELLY RIVER FORMATION)

The Ribstone Creek reservoir of the Whiteside Pool (Figs. 12A and 12B) comprises dominantly well-washed fine-grained sandstones in planar foresets (type-IV elements) with subordinate bioturbated and bedded shaly sandstones. The top of the unit is relatively sharply defined in that the uppermost sandstones are strongly indurated and contain abundant calcite and siderite cement. Similar layers of strongly cemented sandstone occur throughout the sequence. Increasing shaliness of the unit eastwards across the Whiteside Field, combined with the occurrence of strongly indurated sandstone layers, appears to be responsible for an easterly decrease in the net pay. The average net pay is 2.7 m and the average porosity is 35%. The field is located on the southern flank of an irregular anticlinal feature. The producing depth of the reservoir is 229 m.

ECONOMIC PROSPECTS

RANKING OF HYDROCARBON PROSPECTS

The generalized approach to the ranking of hydrocarbon prospects with emphasis on gas occurrences adopted below is taken from previous accounts by the author (Simpson, 1982a, 1984) and considers (1) variation in reservoir quality, (2) possible coincidence of facies belts with structural trends, (3) known occurrences of gas as showings and as commercially significant pools in correlative strata, and (4) depth below surface. These criteria are not listed in preferred order as they have different degrees of importance from one prospect type to another. Ten main prospects are now examined beginning with those judged to be of highest priority.

1. THE BOW ISLAND-VIKING SUCCESSION OF SOUTHWESTERN AND WEST-CENTRAL SASKATCHEWAN

This unit is characterized by a progressive northerly and northeasterly decrease in thickness and grain size across the area. Individual Bow Island sandstone bodies exhibit similar properties in the southwest. Type-II, -III, -IV and -V sequence elements are associated in upward-coarsening sequences in the

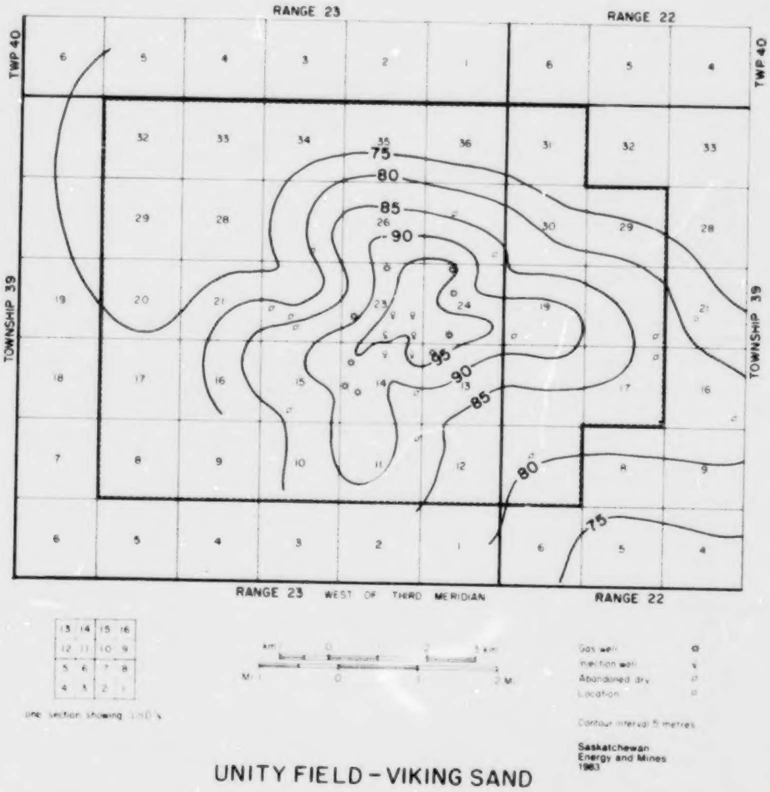

RANGE 23
RANGE 22
TWP 40
TOWNSHIP 39
RANGE 23 WEST OF THIRD MERIDIAN
RANGE 22
75
80
85
90
one section showing LSD's
km 1 0 1 2 3 km
Mi 1 0 1 2 Mi
Gas well
Injection well
Abandoned dry
Location
Contour interval 5 metres
Saskatchewan Energy and Mines 1983
UNITY FIELD - VIKING SAND

Fig. 10A - Structure contours on the Viking Sand of the Unity Pool, west-central Saskatchewan.

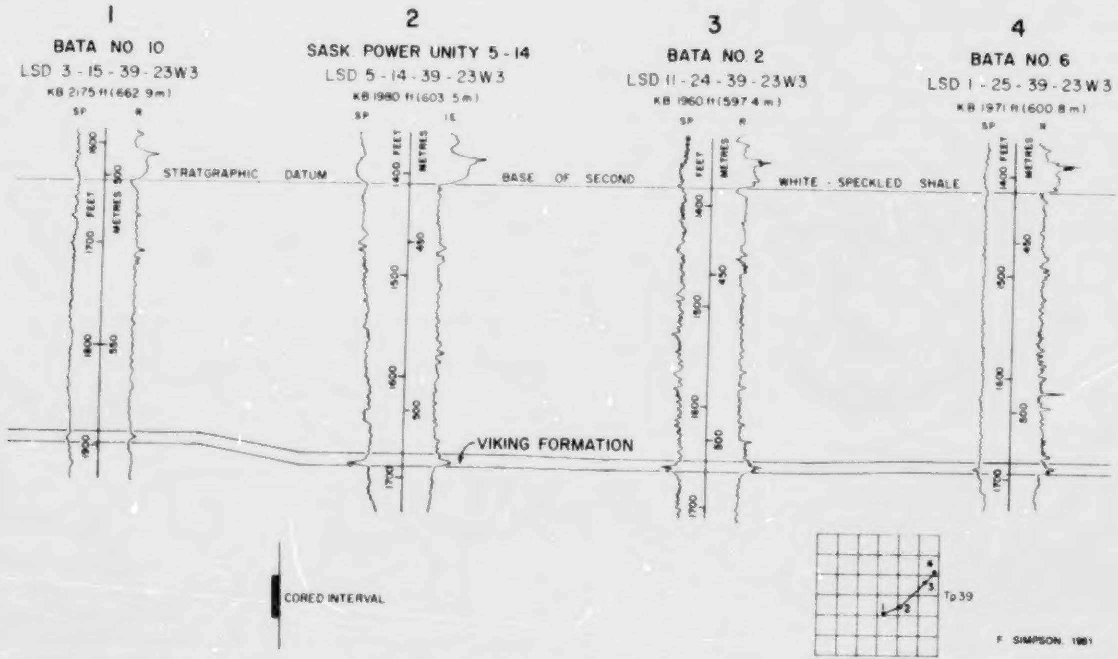

1
BATA NO 10
LSD 3 - 15 - 39 - 23W3
KB 2175 ft (662 9 m)
2
SASK POWER UNITY 5 - 14
LSD 5 - 14 - 39 - 23W3
KB 1980 ft (603 5 m)
3
BATA NO. 2
LSD 11 - 24 - 39 - 23W3
KB 1960 ft (597 4 m)
4
BATA NO. 6
LSD 1 - 25 - 39 - 23W3
KB 1971 ft (600 8 m)
SP
R
FEET
METRES
STRATGRAPHIC DATUM
BASE OF SECOND
WHITE - SPECKLED SHALE
VIKING FORMATION
CORED INTERVAL
Tp 39
R23 W3
F. SIMPSON, 1981

Fig. 10B - Stratigraphic cross-section across the Unity Viking Pool, west-central Saskatchewan.

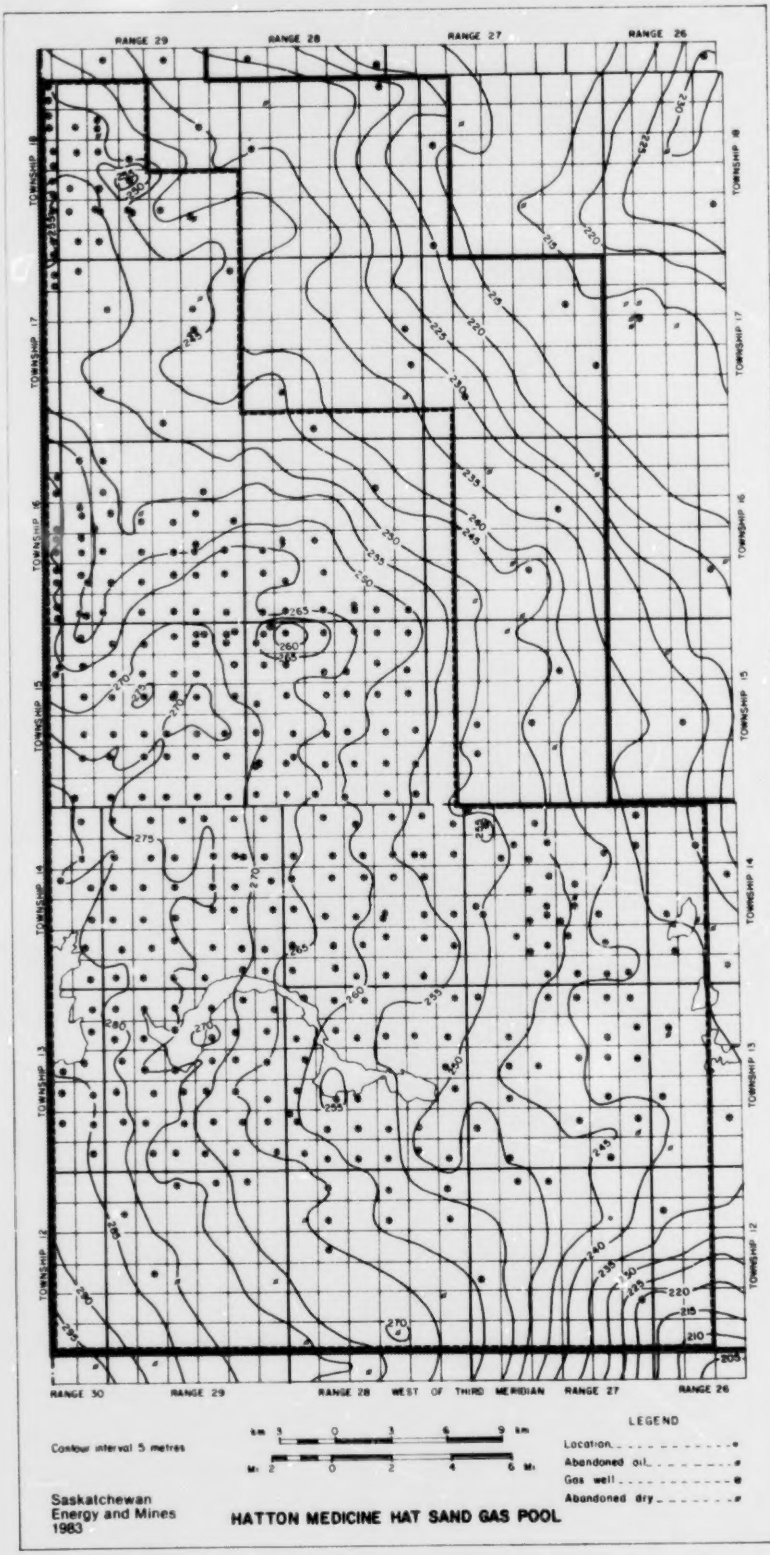
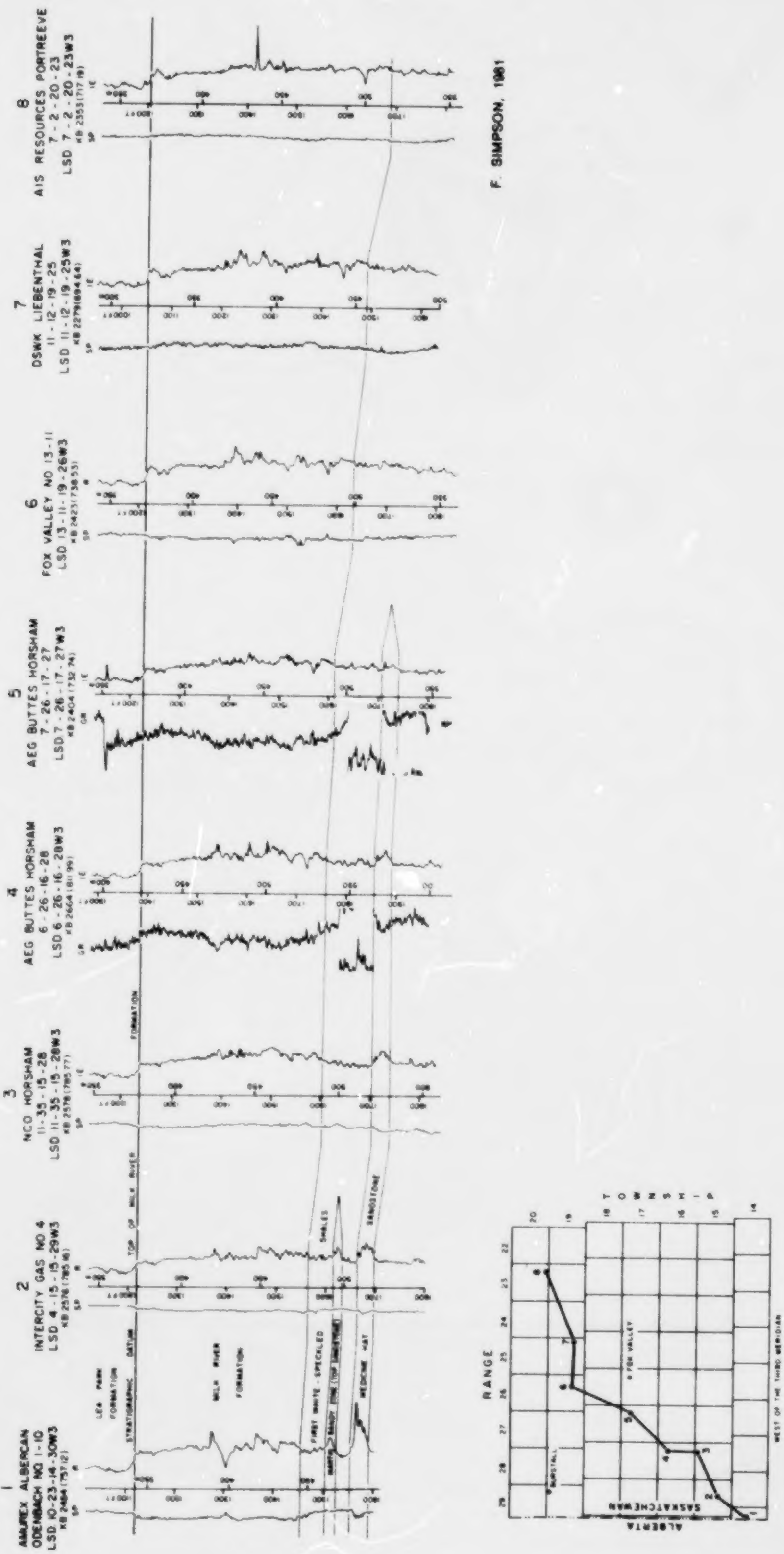

RANGE 29
RANGE 28
RANGE 27
RANGE 26
TOWNSHIP 18
TOWNSHIP 17
TOWNSHIP 16
TOWNSHIP 15
TOWNSHIP 14
TOWNSHIP 13
TOWNSHIP 12
230
225
220
215
220
215
220
225
230
235
240
245
250
255
250
265
260
265
270
275
270
275
270
265
260
255
250
280
270
255
245
240
235
230
225
220
215
210
205
270
280
290
295
RANGE 30
RANGE 29
RANGE 28
WEST OF THIRD MERIDIAN
RANGE 27
RANGE 26
Contour interval 5 metres
km 3 0 3 6 9 km
Mi 2 0 2 4 6 Mi
LEGEND
Location
Abandoned oil
Gas well
Abandoned dry
Saskatchewan
Energy and Mines
1983
HATTON MEDICINE HAT SAND GAS POOL

Fig. 11A - Structure contours on the Medicine Hat Sandstone of the Hatton Pool, southwestern Saskatchewan.


1
AMUREX ALBERCAN
OOENBACH NO 1-10
LSD 10-23-14-30W3
KB 2484 (757.2)
2
INTERCITY GAS NO 4
LSD 4-15-15-29W3
KB 2578 (785.8)
3
NCO HORSHAM
11-35-15-28
LSD 11-35-15-28W3
KB 2578 (785.77)
4
AEG BUTTES HORSHAM
6-26-16-28
LSD 6-26-16-28W3
KB 2664 (811.99)
5
AEG BUTTES HORSHAM
7-26-17-27
LSD 7-26-17-27W3
KB 2404 (732.74)
6
FOX VALLEY NO 13-11
LSD 13-11-19-26W3
KB 2423 (738.53)
7
DSWK LIEBENTHAL
11-12-19-25
LSD 11-12-19-25W3
KB 2279 (694.64)
8
AIS RESOURCES PORTREEVE
7-2-20-23
LSD 7-2-20-23W3
KB 2353 (717.19)
LEA PARK FORMATION
STRATIGRAPHIC DATUM
TOP OF MILK RIVER FORMATION
MILK RIVER FORMATION
FIRST WHITE-SPECKLED SHALES
MEDICINE HAT SANDSTONE
SP
R
GR
RANGE
TOWNSHIP
ALBERTA
SASKATCHEWAN
BURSTALL
FOX VALLEY
WEST OF THE THIRD MERIDIAN

F. SIMPSON, 1981

Fig. 11B - Stratigraphic cross-section across the Hatton (Milk River-Medicine Hat) and Liebenthal (Milk River) Pools, southwestern Saskatchewan.

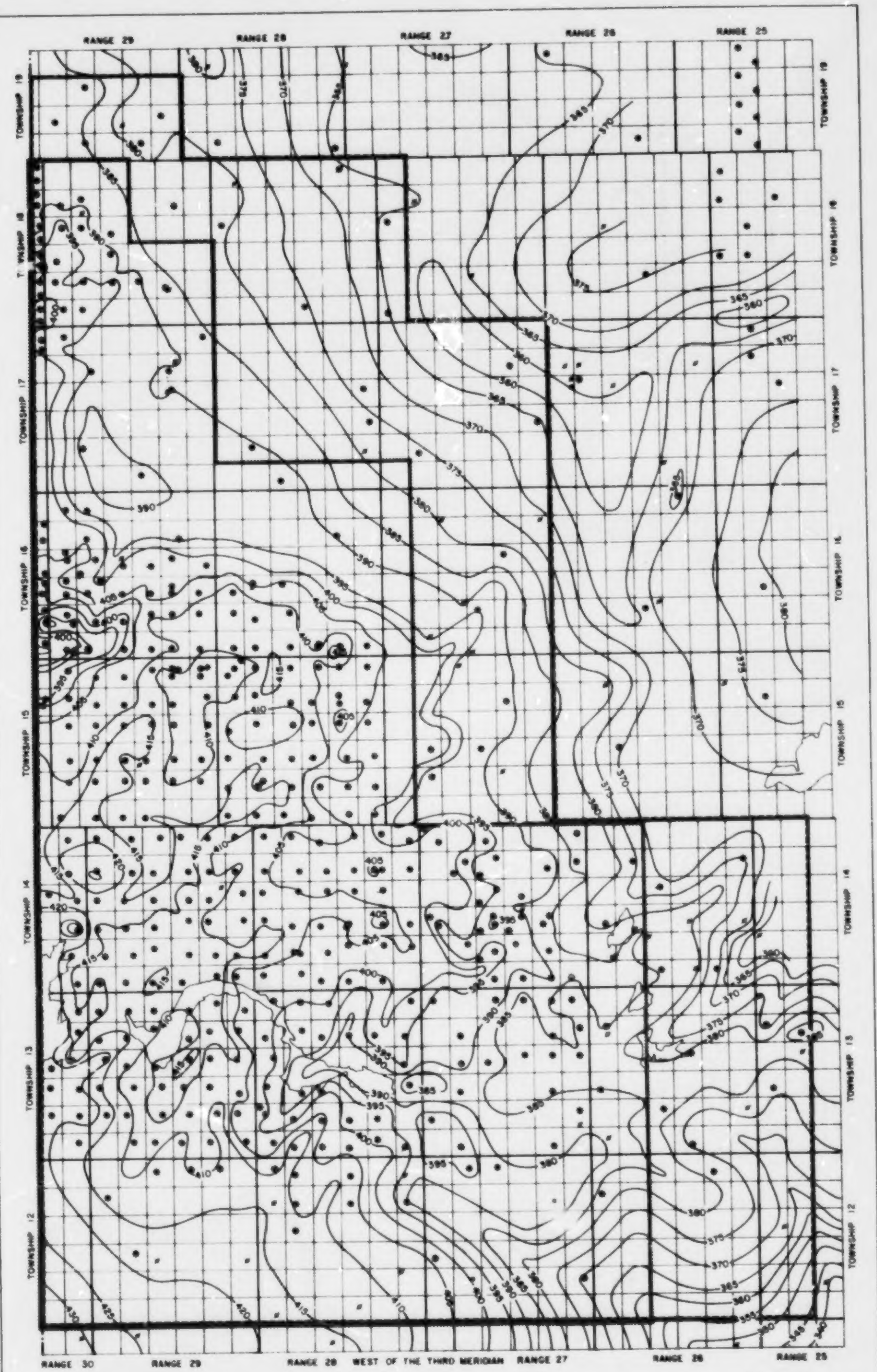

RANGE 29
RANGE 28
RANGE 27
RANGE 26
RANGE 25
TOWNSHIP 19
TOWNSHIP 18
TOWNSHIP 17
TOWNSHIP 16
TOWNSHIP 15
TOWNSHIP 14
TOWNSHIP 13
TOWNSHIP 12
RANGE 30
RANGE 29
RANGE 28 WEST OF THE THIRD MERIDIAN RANGE 27
RANGE 26
RANGE 25
km 3 0 3 6 9 km
Mi 2 0 2 4 6 Mi
Contour interval 5 metres
Saskatchewan
Energy and Mines
1983
HATTON MILK RIVER GAS POOL
LEGEND
Location
Abandoned oil
Gas well
Abandoned gas
Abandoned dry

Fig. 11C - Structure contours on the Milk River Formation of the Hatton Pool, southwestern Saskatchewan.

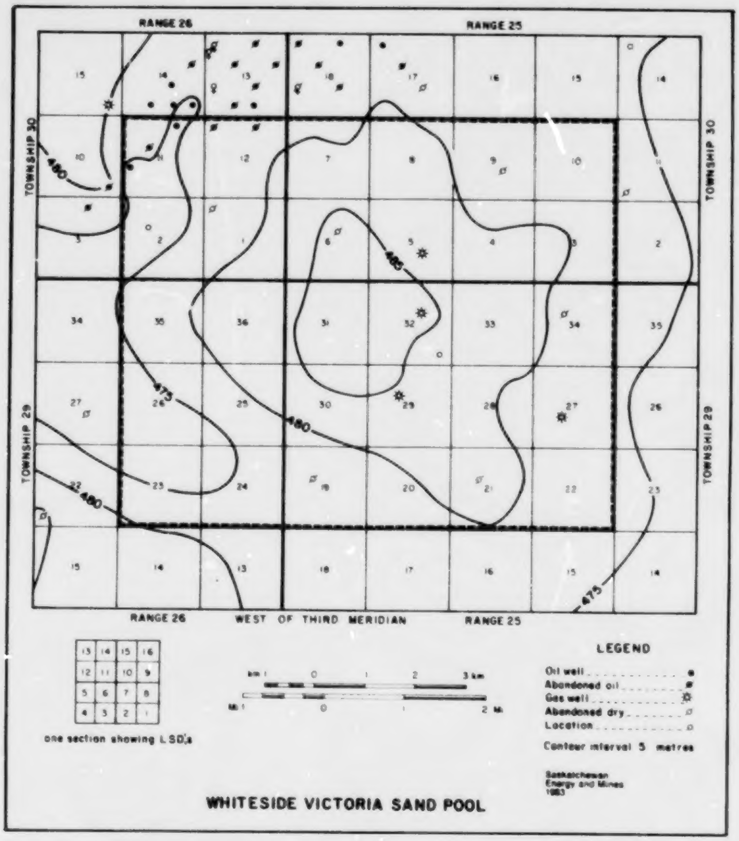

RANGE 26
RANGE 25
TOWNSHIP 30
TOWNSHIP 29
480
485
475
WEST OF THIRD MERIDIAN
one section showing LSD's
LEGEND
Oil well ●
Abandoned oil
Gas well ☼
Abandoned dry
Location ○
Contour interval 5 metres
Saskatchewan Energy and Mines 1983
WHITESIDE VICTORIA SAND POOL

Fig. 12A - Structure contours on the Ribstone Creek Tongue (Belly River Formation) of the Whiteside Pool, west-central Saskatchewan.

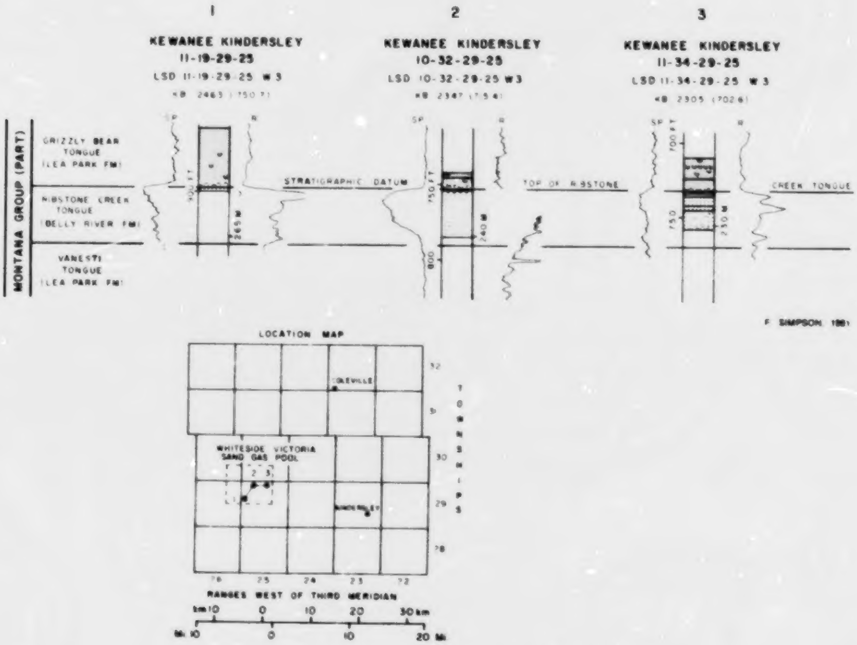

1
KEWANEE KINDERSLEY
11-19-29-25
LSD 11-19-29-25 W3
2
KEWANEE KINDERSLEY
10-32-29-25
LSD 10-32-29-25 W3
3
KEWANEE KINDERSLEY
11-34-29-25
LSD 11-34-29-25 W3
MONTANA GROUP (PART)
GRIZZLY BEAR TONGUE (LEA PARK FM)
RIBSTONE CREEK TONGUE (BELLY RIVER FM)
VANESTI TONGUE (LEA PARK FM)
STRATIGRAPHIC DATUM
TOP OF RIBSTONE CREEK TONGUE
SP
R
F. SIMPSON, 1981
LOCATION MAP
COLEVILLE
WHITESIDE VICTORIA SAND GAS POOL
KINDERSLEY
TOWNSHIPS
RANGES WEST OF THIRD MERIDIAN

Fig. 12B - Stratigraphic cross-section across the Whiteside Ribstone Creek Pool, west-central Saskatchewan.

southern and central parts of the prospective area, but tend to give way to type-II and -III elements to the north and east (Fig. 13). The highest gas potential lies in the Hatton district, farther south and east towards the southern solution edge of the Prairie salt, and between the Jurassic and Mississippian erosional scarps of west-central Saskatchewan. In the Hatton district, hydrocarbon accumulation in the Bow Island-Viking sequence of the Medicine Hat Sandstone and Milk River Formation is probably controlled by basement features. Few showings have yet been recorded in the unit. Drape structures are common in the Viking Formation of west-central Saskatchewan and numerous showings of hydrocarbons exist between the main production locales. In the southwest, both conventional and low-permeability reservoirs occur at depths of over 1000 m and are the deepest prospects considered.

2. THE VIKING-NEWCASTLE SUCCESSION OF SOUTHEASTERN SASKATCHEWAN

In the south-central part of the area, the unit is made up of upward-fining and subordinate upward-coarsening sequences forming mulitstorey sandstone bodies which tend to pinch out to the west and east (Fig. 13). Type-II, -III and -IV sequence elements commonly occur together, although a dominance of shaly type-III elements appears to be fairly widespread. Showings of hydrocarbons are relatively common, and sites of coincidence between basement linear features and solution-generated collapse structures associated with the Prairie Evaporite may provide the most favourable drilling locations. The drilling depths of prospects may be expected in the range 800-1000 m.

3. THE MILK RIVER FORMATION OF SOUTHWESTERN SASKATCHEWAN

The succession is composed largely of shaly sandstones and siltstones in the form of type-III elements. The Middle Unit and the uppermost sandy strata of the Lower Unit, described by Simpson and Singh (1980), are regarded as being most prospective for gas. The most favourable area for drilling is considered to be in the extreme southwest of the province, south of the Hatton district, at locations where the dominant northerly strike of structure contours at the base of the Upper Colorado succession and the top of the Milk River Formation is disrupted by minor east-west deflections probably reflecting basement influences (Fig. 14). The area between Hatton and Liebenthal is also regarded as prospective for gas.

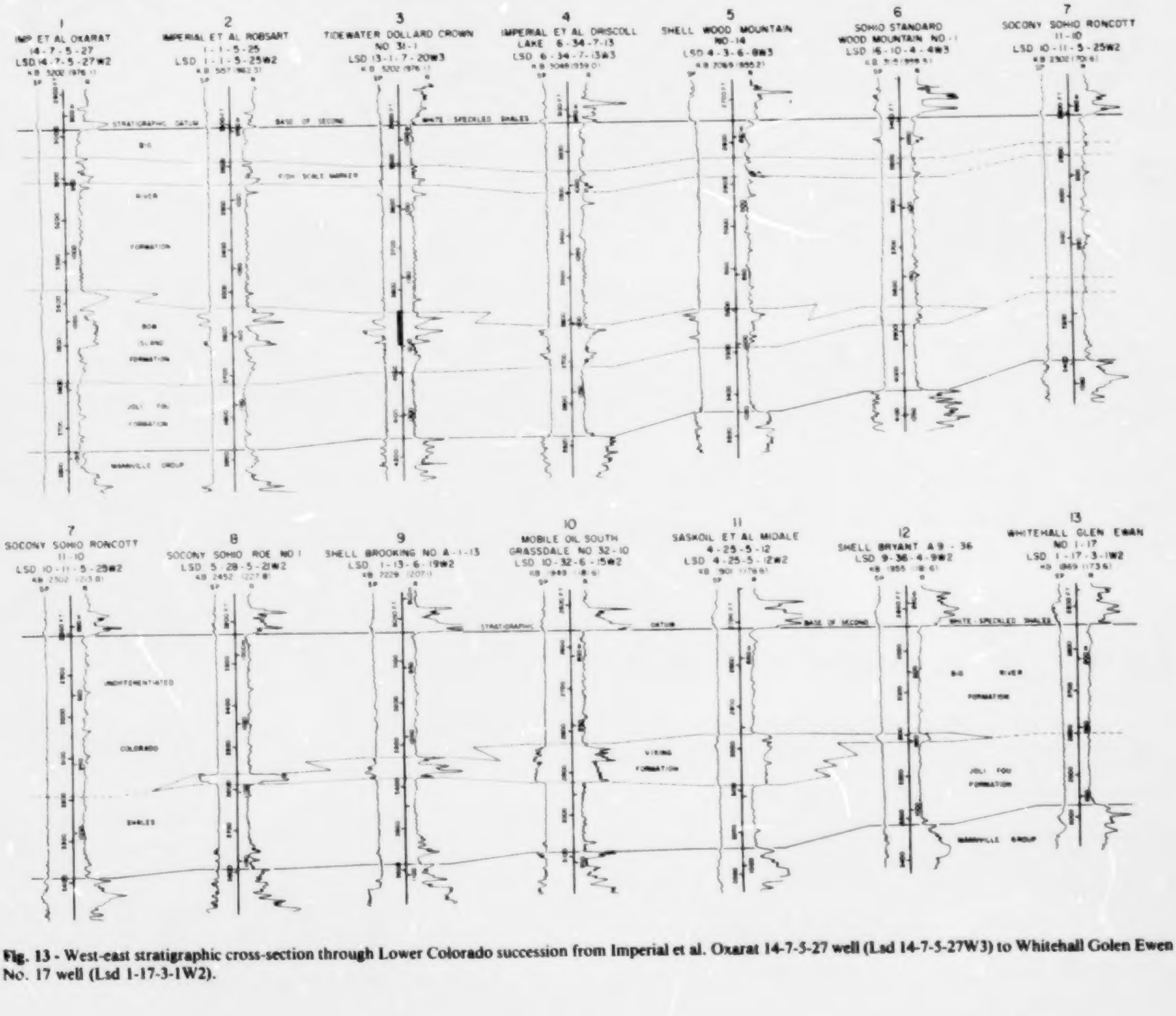

1
IMP ET AL OXARAT 14-7-5-27
LSD 14-7-5-27W2
2
IMPERIAL ET AL ROBSART 1-1-5-25
LSD 1-1-5-25W2
3
TIDEWATER DOLLARD CROWN NO 31-1
LSD 13-1-7-20W3
4
IMPERIAL ET AL DRISCOLL LAKE 6-34-7-13
LSD 6-34-7-13W3
5
SHELL WOOD MOUNTAIN NO-14
LSD 4-3-6-8W3
6
SOHIO STANDARD WOOD MOUNTAIN NO-1
LSD 16-10-4-4W3
7
SOCONY SOHIO RONCOTT 11-10
LSD 10-11-5-25W2
STRATIGRAPHIC DATUM
BASE OF SECOND
WHITE SPECKLED SHALES
BIG RIVER FORMATION
FISH SCALE MARKER
BOW ISLAND FORMATION
JOLI FOU FORMATION
MANNVILLE GROUP
7
SOCONY SOHIO RONCOTT 11-10
LSD 10-11-5-25W2
8
SOCONY SOHIO ROE NO 1
LSD 5-28-5-21W2
9
SHELL BROOKING NO A-1-13
LSD 1-13-6-19W2
10
MOBILE OIL SOUTH GRASSDALE NO 32-10
LSD 10-32-6-15W2
11
SASKOIL ET AL MIDALE 4-25-5-12
LSD 4-25-5-12W2
12
SHELL BRYANT A9-36
LSD 9-36-4-9W2
13
WHITEHALL GLEN EWAN NO 1-17
LSD 1-17-3-1W2
UNDIFFERENTIATED COLORADO SHALES
VIKING FORMATION
BIG RIVER FORMATION
JOLI FOU FORMATION
MANNVILLE GROUP

Fig. 13 - West-east stratigraphic cross-section through Lower Colorado succession from Imperial et al. Oxarat 14-7-5-27 well (Lsd 14-7-5-27W3) to Whitehall Golen Ewen No. 17 well (Lsd 1-17-3-1W2).

4. THE PHILLIPS SANDSTONE AND BOWDOIN SANDSTONE OF SOUTHWESTERN AND SOUTH-CENTRAL SASKATCHEWAN

The Phillips Sandstone (Fig. 15) is composed mainly of type-II sequence elements, although scarce type-III elements also occur in extreme southwestern locations. Upward-coarsening sequences defined by progressive upward decrease in the poroportion of intercalated mudstone are common. The Bowdoin Sandstone appears to be made up of type-II elements only. Both units progressively decrease in grain size northwards. The rationale underlying exploration for Phillips Sandstone reservoirs south of Hatton is similar to that outlined for the Milk River Formation. The Bowdoin Sandstone is likely to take on increased importance in south-central Saskatchewan, particularly to the immediate north of the Bowdoin Field of north-central Montana.

5. THE MEDICINE HAT SANDSTONE OF SOUTHWESTERN SASKATCHEWAN

The Medicine Hat Sandstone consists of type-III and type-II elements arranged in dominantly upward-coarsening sequences. The most prospective area for gas in the unit is to the immediate south of the Hatton Field.

6. THE RIBSTONE CREEK TONGUE OF THE BELLY RIVER FORMATION IN SOUTHWEST AND SOUTH-CENTRAL SASKATCHEWAN

The Ribstone Creek Tongue and other Belly River subdivisions (Fig. 16) are seen as type-II, -III, and -IV sequence elements, and are prospective for gas at locations considered favourable for Milk River and Upper Colorado reservoirs.

7. THE SPINNEY HILL SANDSTONE OF WEST-CENTRAL SASKATCHEWAN

The Spinney Hill Sandstone is made up of type-II, -III, and -IV elements arranged in repeated upward-fining sequences in west-central Saskatchewan. The eastern part of the Dodsland-Hoosier production district is regarded as prospective for Spinney Hill gas. Farther west, the unit undergoes progressive increase in the amount of intercalated shale.

8. THE ST. WALBURG SANDSTONE OF WEST-CENTRAL SASKATCHEWAN

The unit consists of type-III and -III sequence elements in generalized upward-coarsening sequences which decrease pronouncedly in thickness and grain size to the west and south (Fig. 17). The most prospective locations are in the vicinity of the Meadow Lake escarpment near the Fourth Meridian.

9. THE FISH-SCALE SANDSTONE OF SOUTHWESTERN SASKATCHEWAN

The Fish-Scale Sandstone and associated Lower Colorado strata are composed of type-II sequence elements, and may be regarded as prospective for hydrocarbons at locations considered favourable for Milk River and Upper Colorado reservoirs.

10. THE SHALY CHALKS AND CALCAREOUS SHALES OF THE UPPER COLORADO SUCCESSION IN SOUTHWESTERN SASKATCHEWAN

These rocks are made up of type-I and type-II sequence elements with the relatively coarse-grained layers composed of pelecypod debris, foraminiferal tests and other fragments in a chalk matrix. The most prospective areas are likely to be those highlighted for the Milk River and Upper Colorado successions. At these locations, the First White-Speckled Shale and the Greenhorn Lime should also be tested. The latter unit may be prospective in south-central Saskatchewan to the north of the Bowdoin Field.

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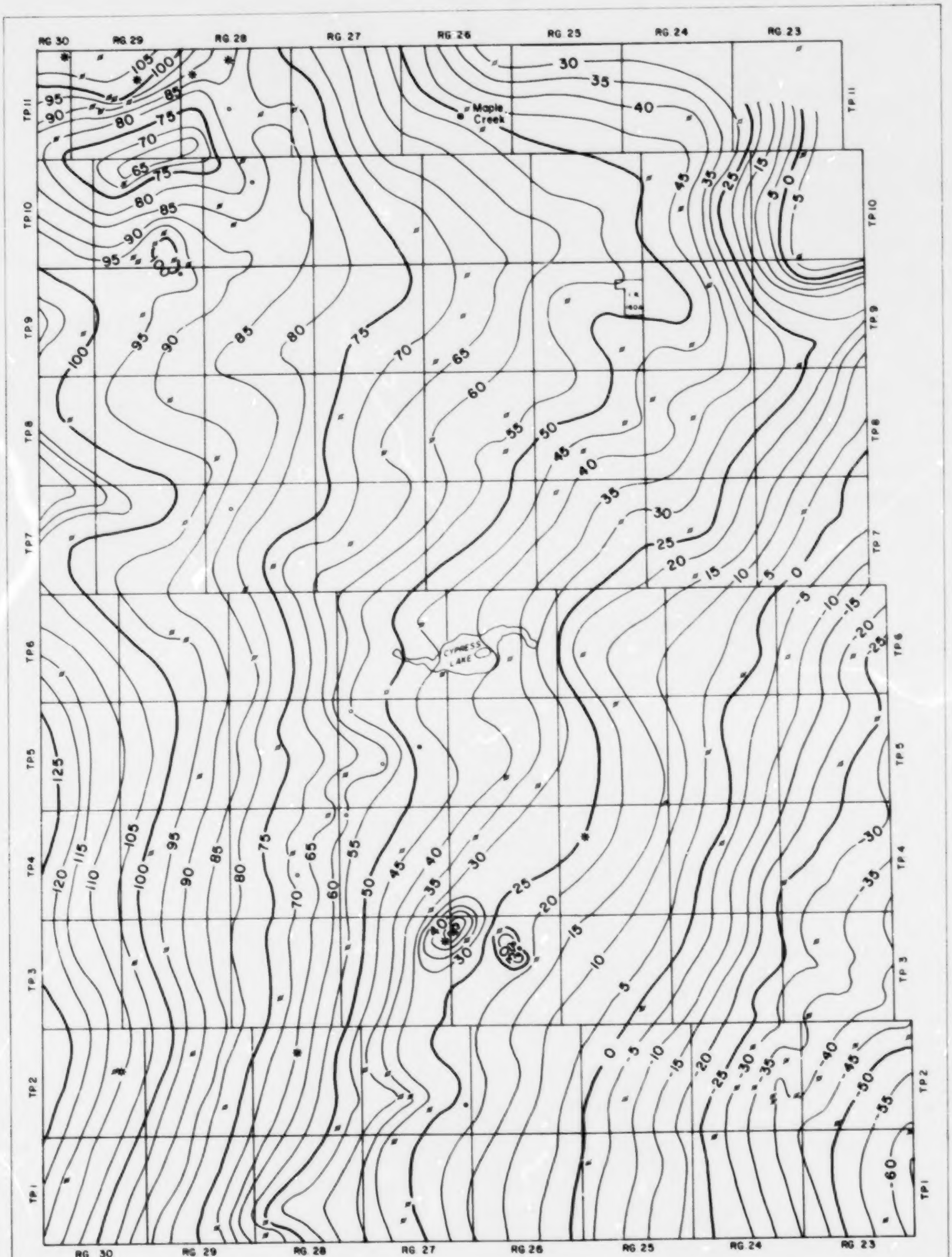
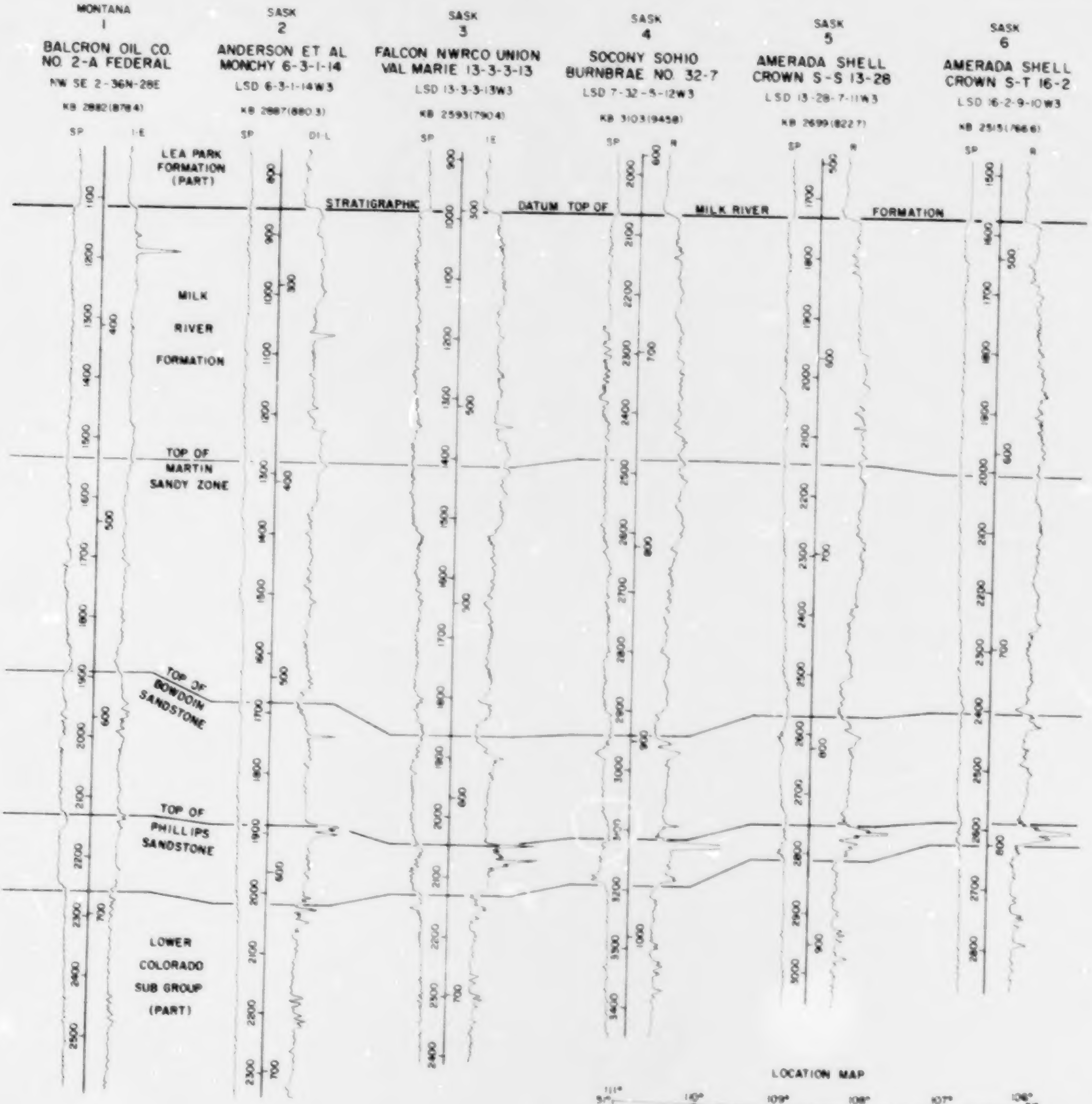

RG 30
RG 29
RG 28
RG 27
RG 26
RG 25
RG 24
RG 23
TP 11
TP 10
TP 9
TP 8
TP 7
TP 6
TP 5
TP 4
TP 3
TP 2
TP 1
Maple Creek
Cypress Lake
km 0 1 2 3 4 5 6 7 8 9 10 km
Mi. 0 1 2 3 4 5 6 Mi.
Contour interval in metres —25—
von Ledebur,1972

Fig. 14 - Structure contours on base of Second White-Speckled Shale in southwestern Saskatchewan (CI = 5 m).


MONTANA
1
BALCRON OIL CO.
NO. 2-A FEDERAL
NW SE 2-36N-28E
KB 2882(878.4)
SP
I-E
SASK
2
ANDERSON ET AL
MONCHY 6-3-1-14
LSD 6-3-1-14W3
KB 2887(880.3)
SP
DI-L
SASK
3
FALCON NWRCO UNION
VAL MARIE 13-3-3-13
LSD 13-3-3-13W3
KB 2593(790.4)
SP
IE
SASK
4
SOCONY SOHIO
BURNBRAE NO. 32-7
LSD 7-32-5-12W3
KB 3103(945.8)
SP
R
SASK
5
AMERADA SHELL
CROWN S-S 13-28
LSD 13-28-7-11W3
KB 2699(822.7)
SP
R
SASK
6
AMERADA SHELL
CROWN S-T 16-2
LSD 16-2-9-10W3
KB 2515(766.6)
SP
R
LEA PARK FORMATION (PART)
STRATIGRAPHIC DATUM TOP OF MILK RIVER FORMATION
MILK RIVER FORMATION
TOP OF MARTIN SANDY ZONE
TOP OF BOWDOIN SANDSTONE
TOP OF PHILLIPS SANDSTONE
LOWER COLORADO SUB GROUP (PART)

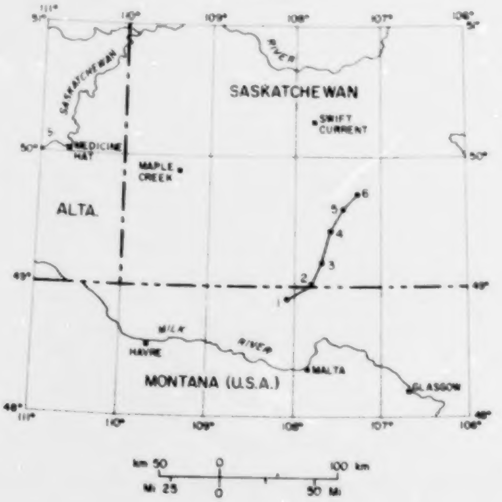

LOCATION MAP
111°
110°
109°
108°
107°
106°
51°
50°
49°
48°
SASKATCHEWAN
RIVER
SASKATCHEWAN
SWIFT CURRENT
MEDICINE HAT
MAPLE CREEK
ALTA.
1
2
3
4
5
6
MILK RIVER
HAVRE
MALTA
GLASGOW
MONTANA (U.S.A.)
km 50
0
100 km
Mi 25
0
50 Mi

Fig. 15 - Southwest-northeast stratigraphic cross-section through Upper Colorado succession from Balcron Oil Co. No. 2-A Federal (NW SE 2-36N-28E) to Amerada Shell Crown S-T 16-2 (Lsd 16-2-9-10W3).

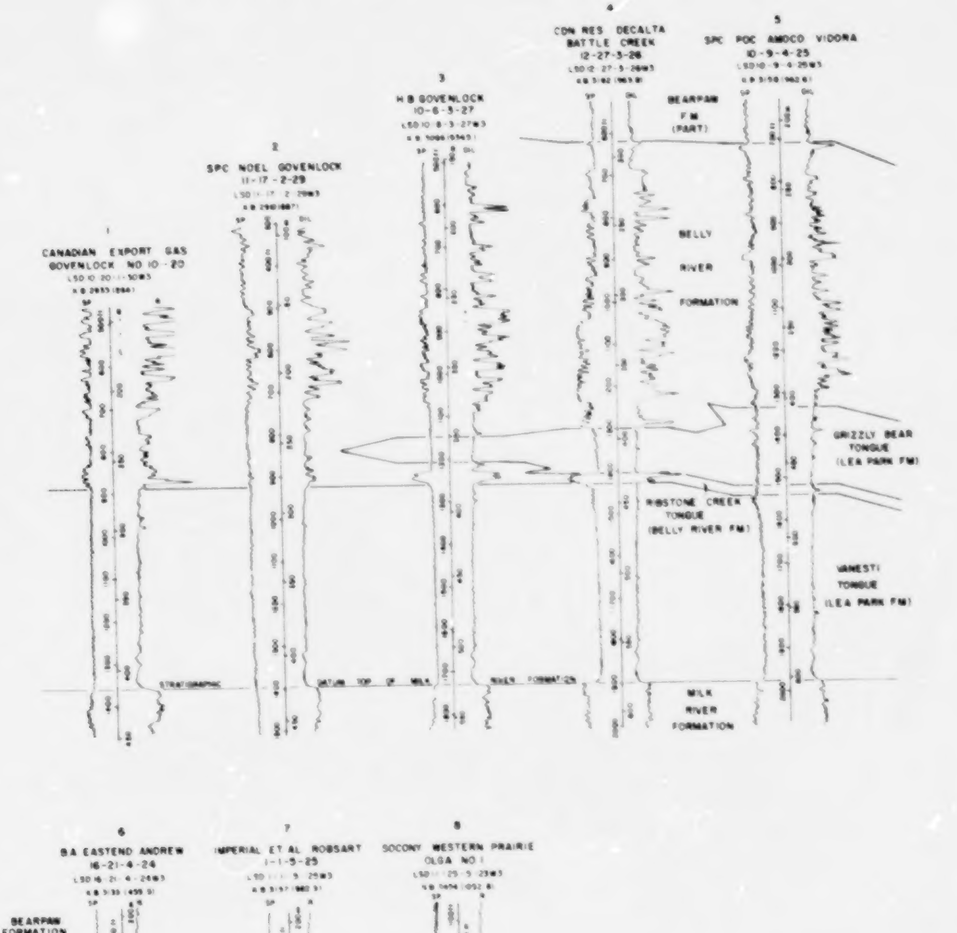

1
CANADIAN EXPORT GAS
GOVENLOCK NO 10-20
LSD 10-20-1-30W3
2
SPC NOEL GOVENLOCK
11-17-2-29
LSD 11-17-2-29W3
3
H B GOVENLOCK
10-6-3-27
LSD 10-6-3-27W3
4
CDN RES DECALTA
BATTLE CREEK
12-27-3-26
LSD 12-27-3-26W3
5
SPC POC AMOCO VIDORA
10-9-4-25
LSD 10-9-4-25W3
SP
DIL
BEARPAW
FM
(PART)
BELLY
RIVER
FORMATION
GRIZZLY BEAR
TONGUE
(LEA PARK FM)
RIBSTONE CREEK
TONGUE
(BELLY RIVER FM)
VANESTI
TONGUE
(LEA PARK FM)
STRATIGRAPHIC DATUM TOP OF MILK RIVER FORMATION
MILK
RIVER
FORMATION
6
BA EASTEND ANDREW
16-21-4-24
LSD 16-21-4-24W3
7
IMPERIAL ET AL ROBSART
1-1-5-25
LSD 1-1-5-25W3
8
SOCONY WESTERN PRAIRIE
OLGA NO 1
LSD 11-25-5-23W3
SP
R
BEARPAW
FORMATION
(PART)
BELLY
RIVER
FM
GRIZZLY BEAR
TONGUE
(LEA PARK FM)
RIBSTONE CREEK
TONGUE
(BELLY RIVER FM)
VANESTI
TONGUE
(LEA PARK FM)
STRATIGRAPHIC DATUM TOP OF THE MILK RIVER FM
MILK
RIVER
FM
LOCATION MAP
CYPRESS LAKE
EASTEND
RANGES WEST OF THIRD MERIDIAN

Fig. 16 - Southwest-northeast stratigraphic cross-section through Belly River Formation from Canadian Export Gas Govenlock No. 10-20 well (Lsd 10-20-1-30W3) to Socony Western Prairie Olga No. 1 well (Lsd 11-25-5-23W3).

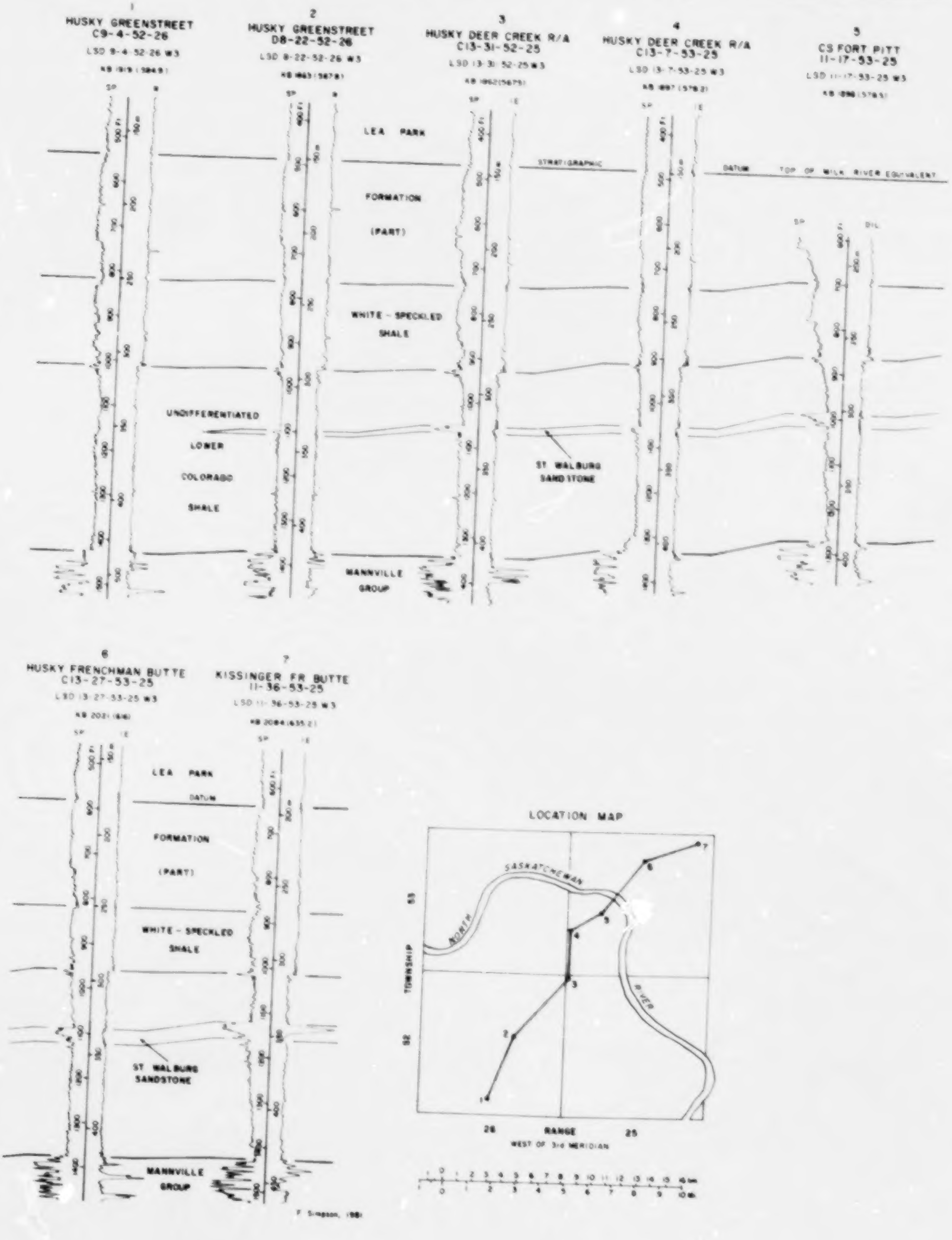

1
HUSKY GREENSTREET
C9-4-52-26
LSD 9-4-52-26 W3
2
HUSKY GREENSTREET
D8-22-52-26
LSD 8-22-52-26 W3
3
HUSKY DEER CREEK R/A
C13-31-52-25
LSD 13-31-52-25 W3
4
HUSKY DEER CREEK R/A
C13-7-53-25
LSD 13-7-53-25 W3
5
CS FORT PITT
11-17-53-25
LSD 11-17-53-25 W3
SP
IE
DIL
LEA PARK
FORMATION
(PART)
STRATIGRAPHIC
DATUM
TOP OF MILK RIVER EQUIVALENT
WHITE - SPECKLED
SHALE
UNDIFFERENTIATED
LOWER
COLORADO
SHALE
ST. WALBURG
SANDSTONE
MANNVILLE
GROUP
6
HUSKY FRENCHMAN BUTTE
C13-27-53-25
LSD 13-27-53-25 W3
KB 2021 (616)
7
KISSINGER FR BUTTE
11-36-53-25
LSD 11-36-53-25 W3
KB 2084 (635.2)
LOCATION MAP
NORTH
SASKATCHEWAN
RIVER
TOWNSHIP
53
52
26
RANGE
25
WEST OF 3rd MERIDIAN
F. Simpson, 1981

Fig. 17 - Southwest-northeast stratigraphic cross-section through Colorado Group from Husky Greenstreet C9-4-52-26 well (Lsd 9-4-52-26W3) to Kissinger Fr. Butte 11-36-53-25 well (Lsd 11-36-53-25W3).

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RESERVOIR QUALITY OF THE VIKING FORMATION, DODSLAND AREA, SASKATCHEWAN

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ABSTRACT

Cores of the Viking Formation from seven wells in the Dodsland Field and surrounding area were examined in detail to provide petrologic data to aid in selection of efficient exploitation methods. Study techniques included core examination, X-ray diffraction, scanning electron microscopy and thin section petrography.

Viking sediments are Upper Albian marine deposits which have been shown to be linear offshore sand bodies enclosed in shale. The sandstones are commonly parallel to paleoshorelines in Alberta and have been recently interpreted to be barrier island (Tizzard and Lerbekmo, 1975) or shelf (Beaumont, 1984) sandstones. In the Dodsland area of Saskatchewan, sandstones appear to occur at high angles to the paleoshoreline and have been interpreted to be tidal sand ridge deposits (Evans, 1970). Both storm-generated shelf sandstones and tidal ridge sandstones may coarsen upwards and are thus not easily differentiated. The linear sandstone bodies may all represent storm-generated shelf deposits.

Cores from the study wells consist of interlaminated shales, siltstones, and sandstones. Black shale containing sand lenses grades into black carbonaceous shale above and below. Porosity and permeability are highest in the sands, with communication between sandstone lenses via very low porosity and permeability siltstones or shales. Porosity types within the sandstones include intergranular porosity and significant amounts of microporosity associated with clay mineral assemblages.

Sandstones in all the cores examined are typically sublitharenites which locally grade into siltstones of similar composition. The sandstones are poorly cemented by quartz, siderite, pyrite, and kaolinite. Detrital and authigenic clay minerals play a significant role in porosity and permeability reduction. These clays include smectite, illite (often with smectite interlayers), and trace to minor amounts of kaolinite and chlorite.

INTRODUCTION

The Viking Formation in southwest Saskatchewan, in particular the Dodsland area, has been subject to extensive exploration. In contrast to the Viking Formation of Alberta, little recent work has been done on the petrology of the Saskatchewan oil bearing sequence. The subject of this paper is a petrologic appraisal of the Viking Formation to provide a better understanding of the desirable and undesirable features which characterise this often marginal reservoir. Examination and detailed petrographic studies on cores of producing Viking strata from seven wells provide the basis for the study and its application to the surrounding potentially productive Viking Formation. Four cores studied are from wells at the following locations: 2-32-26-19W3; 7-17-30-20W3; 12-24-31-20W3; and 16-16-30-21W3. Three of the cores studied are confidential.

STRATIGRAPHY

The first reference to the Viking Formation was by Slipper (1918) in which he refers to the Viking gas sand, a producing horizon of the Colorado Group near the town of Viking in east central Alberta. The Viking Formation is now recognized to be Upper Albian in age and is underlain by the Joli Fou shale and overlain by the Colorado shale (Fig. 1). The overlying Colorado shale is conformable with the Viking Formation but the underlying Joil Fou may be unconformable. This unconformity is indicated by westward thinning of the Joli Fou and a sand-filled desiccation crack in the Joli Fou about 3m below the Viking contact (Jones, 1961).

The Viking Formation in the study area consists of very fine to coarse sand, silt, and silty shale. Chert pebbles and glauconite are common. The Formation is about 20 m thick near Viking, Alberta. It thickens to more than 75 m to the west and south and "shales out" to the east and north (Norgaard, 1954).

GEOLOGICAL SETTING AND DEPOSITIONAL ENVIRONMENT

Viking sediments make up part of Sloss's (1963) Zuni Sequence; they were deposited in a shallow epeiric sea which covered much of the North American craton during the Cretaceous. This sea was bounded by the cordilleran orogen to the west and the emergent centre of the craton to the east. The paleographically high cordilleran region supplied most of the sediment to the basin at this time. The Viking Formation thickens towards this westerly source (Beaumont, 1984).

Environmental interpretation of the Viking Formation has been the subject of some controversy. Viking sediments have been interpreted to be deep water turbidites (Beach, 1955) and barrier island deposits (Tizzard and Lerbekmo, 1975). Deposition on a shallow marine shelf, dominated by either tidal (Evans, 1970; Simpson, 1975) or storm-generated currents (Beaumont, 1984) is more probable.

Recent research on continental shelf sands along the east coast of the United States (*e.g.*, Duane *et al.*, 1972; Swift *e al.*, 1972) has provided a modern analogue for some marine sandstone sequences. Viking sandstones are enclosed in marine shales and were probably formed into linear ridges by storm activity. Since these sand ridges are enclosed in marine shales i is probable that they were at a moderate distance from th shoreline. The emplacement of sands and gravels tens o kilometres offshore onto the shaly shelf is problematic. Linea sand ridges may be formed subparallel to the shoreline durin a transgressive period as suggested by Duane *et al.* (1972) o the may form by the storm reworking of turbidite or strean deposits. The modification of turbidite deposits by storm processes is suggested by Walker (1983) for the Cardium Formation in Alberta. Beaumont (1984) suggests that pebbles in th

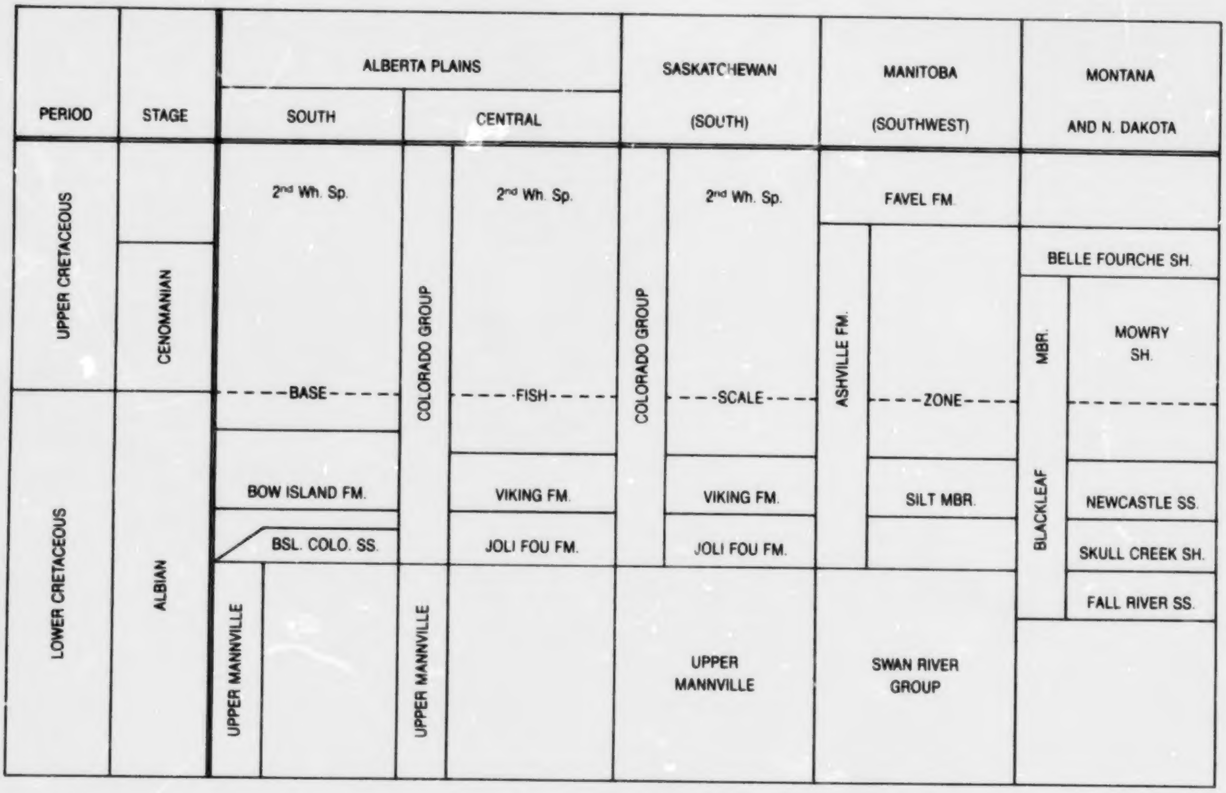

PERIOD
STAGE
ALBERTA PLAINS
SOUTH
CENTRAL
SASKATCHEWAN
(SOUTH)
MANITOBA
(SOUTHWEST)
MONTANA
AND N. DAKOTA
UPPER CRETACEOUS
LOWER CRETACEOUS
CENOMANIAN
ALBIAN
2nd Wh. Sp.
2nd Wh. Sp.
2nd Wh. Sp.
FAVEL FM.
BELLE FOURCHE SH.
COLORADO GROUP
COLORADO GROUP
ASHVILLE FM.
MBR.
MOWRY SH.
BASE
FISH
SCALE
ZONE
BOW ISLAND FM.
VIKING FM.
VIKING FM.
SILT MBR.
BLACKLEAF
NEWCASTLE SS.
BSL. COLO. SS.
JOLI FOU FM.
JOLI FOU FM.
SKULL CREEK SH.
FALL RIVER SS.
UPPER MANNVILLE
UPPER MANNVILLE
UPPER MANNVILLE
SWAN RIVER GROUP

Fig. 1 - Correlation chart of the Viking Formation and associated strata (after Rudkin, 1964).

Viking Formation were transported across the shelf by streams during repeated regressive cycles and later reworked.

The facies of the Viking observed by the writers in the Dodsland area are similar to those described by Beaumont (1984) for the Viking Formation in Alberta, although Viking sediments in the Dodsland and surrounding area represent more distal deposits.

STUDY TECHNIQUES

Samples for petrographic studies were selected following core examination and detailed core description. Sample selection was aided by the use of core porosity and permeability data, and examination of the cores under normal and ultraviolet light. X-ray diffraction, scanning electron microscopy, and thin section petrography of both sandstone and shale samples provide the basis for this study.

X-Ray Diffration

Samples for x-ray diffraction analysis were selected to represent the range of visible lithologies and measured porosity and permeability. Sand samples were selected to be essentially free of shale lenses, while shales were essentially sand free. Samples were separated into greater than and less than 5 micron size fractions to facilitate accurate identification and semi-quantification of the component minerals, particularly clays. Disaggregation of the samples was achieved by sonification and dispersion in a sodium hexametaphosphate solution. Clays were flocculated in a magnesium chloride solution and separated by centrifuge. Each size fraction was analyzed separately. The less than 5 micron size fraction was analyzed at room relative humidity, glycolated, heat treated, and acidized in dilute hydrochloric acid. The resulting diffractograms were interpreted using the JCPDS Powder Diffraction File and the Clay Mineral Society's Clay Standards diffractograms. Weight percentages were calculated using an external standard method and bulk composition calculated from the relative weight percentages and size fraction weights.

Scanning Electron Microscopy

Representative samples of the sand were prepared by mounting on an aluminum stub and coating with gold to provide a conductive surface. Where possible, samples of sand in contact with shale laminae were used. The specimens were then examined using a Cambridge Stereoscan equipped with an energy dispersive X-ray analyzer. The analyzer was used to aid in identification of the clays which are indistinguishable by morphology alone.

Thin Section Petrography

Thin sections of the sand enclosed by shales were prepared in a routine manner after impregnation of the samples. A combination of vacuum and high pressure techniques using low viscosity blue dyed epoxy resin was used to maximize impregnation of friable samples and to allow the identification of porosity in low permeability zones. The water sensitive nature of the samples precluded cutting in water, so preparation was carried out using oils and sections were dry finished.

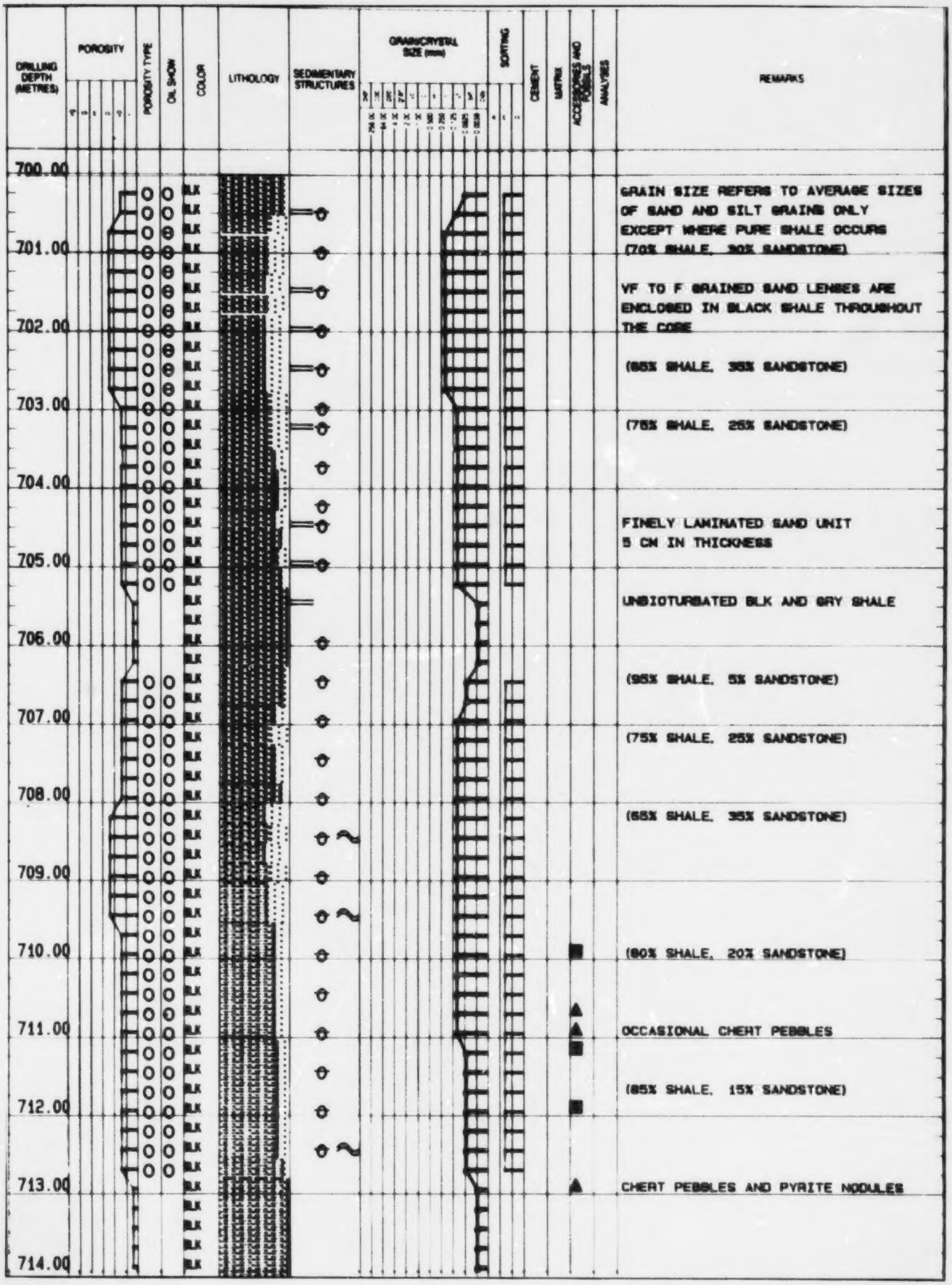

DRILLING DEPTH (METRES)
POROSITY
POROSITY TYPE
OIL SHOW
COLOR
LITHOLOGY
SEDIMENTARY STRUCTURES
GRAIN/CRYSTAL SIZE (mm)
SORTING
CEMENT
MATRIX
ACCESSORIES AND FOSSILS
ANALYSES
REMARKS
700.00
701.00
702.00
703.00
704.00
705.00
706.00
707.00
708.00
709.00
710.00
711.00
712.00
713.00
714.00
BLK
GRAIN SIZE REFERS TO AVERAGE SIZES OF SAND AND SILT GRAINS ONLY EXCEPT WHERE PURE SHALE OCCURS
(70% SHALE, 30% SANDSTONE)
VF TO F GRAINED SAND LENSES ARE ENCLOSED IN BLACK SHALE THROUGHOUT THE CORE
(65% SHALE, 35% SANDSTONE)
(75% SHALE, 25% SANDSTONE)
FINELY LAMINATED SAND UNIT 5 CM IN THICKNESS
UNBIOTURBATED BLK AND GRY SHALE
(95% SHALE, 5% SANDSTONE)
(75% SHALE, 25% SANDSTONE)
(65% SHALE, 35% SANDSTONE)
(80% SHALE, 20% SANDSTONE)
OCCASIONAL CHERT PEBBLES
(85% SHALE, 15% SANDSTONE)
CHERT PEBBLES AND PYRITE NODULES

Fig. 2 - Typical Viking section, Dodsland area, Saskatchewan.

LITHOLOGY

The Viking Formation in the study wells shows some well to well variation, but a general pattern is recognisable in all wells. The typical section consists of two similar slightly coarsening upwards sandy sequences separated by about 1 m of shale (Fig. 2). Pebble bands composed predominantly of chert are present toward the base of the lower sandy shale unit. Separation of sandy shales from shale can be difficult locally due to the gradational nature of the contacts in many wells. Sand concentration and sedimentary structure provide the most reliable criteria for separation in these locations. This is greatly aided by core examination under ultraviolet light as most of the sand is saturated with oil.

The sandy shale units contain very fine to fine grained sand which occasionally becomes coarser upwards. Sorting is typically moderate, throughout. Sand content commonly increases towards the top of each of the sandy shale units with bioturbated and parallel stratified zones preserved. Sand is concentrated in lenticular or wavy bedded intervals and only rarely occurs in distinguishable beds of any substantial thickness.

The upper sandy shale is often of better reservoir quality, in that it contains more sand and is commonly coarser grained than the lower sandy shale. Wavy stratification is more common in the lower unit. Pebble bands and pyrite nodules are also present in the lower sandy shale sequence. In some locations the sandy shale grades into a siltstone.

PETROLOGY

Mineralogy

Samples from the interbedded sandstones, siltstones, and shales all exhibit similar bulk mineralogy as indicated by X-ray diffraction analysis (Table 1). Sands are composed predominantly of quartz with lesser amounts of clay minerals and minor feldspar. Occasional trace to minor amounts of dolomite, siderite, and pyrite are also present (Fig. 3). Clay minerals are principally illite, smectite, and mixed layer clays with minor amounts of kaolinite and chlorite (Table 2, Fig. 4).

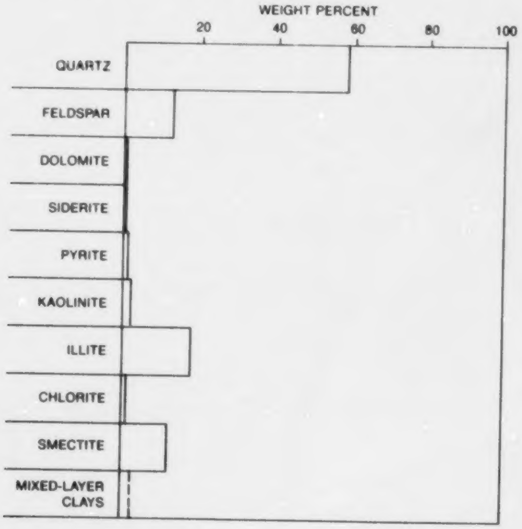


Fig. 3 - Average bulk mineralogy histogram of the Viking sand determined from X-ray diffraction data.

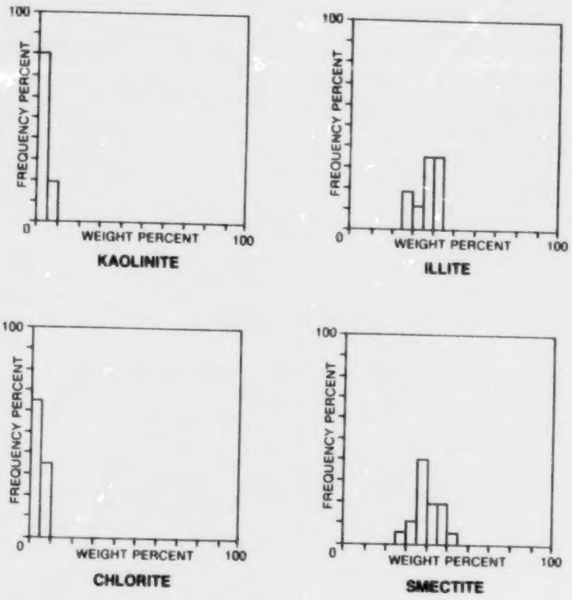
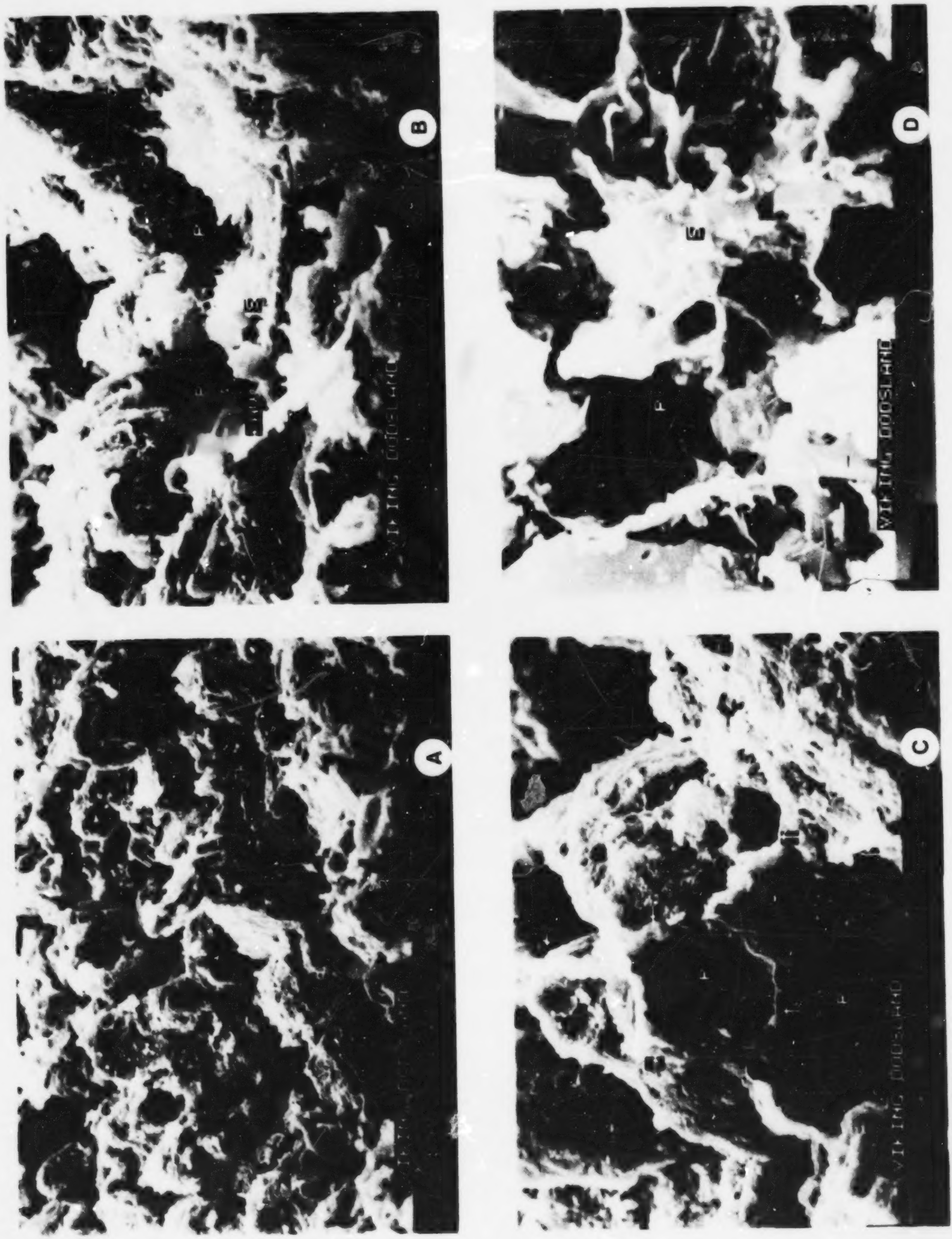


Fig. 4 - Clay mineral histograms for the less than 5 micron size fraction of the Viking sand determined by X-ray diffraction.

QUARTZ	FELDSPAR	DOLOMITE	SIDERITE	PYRITE	KAOLINITE	ILLITE	CHRORITE	SMECTITE	MIXED-LAYER CLAYS
58	12	NIL	NIL	1	3	15	2	9	PR
64	10	NIL	NIL	1	1	9	1	14	PR
51	10	NIL	NIL	2	3	21	2	11	PR
53	11	NIL	NIL	1	3	19	3	10	PR
51	11	NIL	NIL	TR	TR	17	3	18	PR
52	11	NIL	NIL	1	TR	15	3	18	PR
52	7	NIL	TR	2	1	19	2	17	PR
52	10	TR	NIL	1	2	20	1	14	PR
47	9	TR	NIL	1	2	23	1	17	PR
56	11	TR	NIL	1	1	17	1	13	PR
50	10	TR	NIL	1	1	20	1	17	PR
59	10	TR	NIL	4	1	11	1	14	PR
68	11	NIL	NIL	NIL	1	11	1	8	PR
69	12	NIL	NIL	TR	1	11	1	6	PR
59	11	NIL	NIL	1	1	16	1	11	PR
63	12	NIL	NIL	TR	1	14	1	9	PR
61	12	NIL	NIL	1	1	14	1	10	PR
30*	7	NIL	NIL	TR	3	30	3	27	PR
17*	3	NIL	NIL	1	4	43	3	29	PR
17*	1	NIL	NIL	1	4	36	3	38	PR

Table 1 - Summary of bluk mineralogy of Viking Formation samples analyzed by X-ray diffraction. * Denotes shale samples.

Fig. 5 - a). General view of a very fine sand and silt lens. Quartz and feldspar grains are heavily coated by detrital and authigenic clays. b). Framework grains are heavily coated by clays, predominantly smectite (S). Pores (P) are lined by clays creating surface microporosity. Quartz overgrowths (AQ) are visible where clays are absent. c). Detrital clays locally form bridges across pore spaces (arrowed), thus reducing permeability. d). Authigenic smectite clays (S) on detrital clays create a relatively high porosity micropore system (P).


A
B
C
D
E
F
VIKING DODSLAND

KAOLINITE	ILLITE	CHLORITE	SMECTITE	MIXED-LAYER CLAYS	NON-CLAY MINERALS	WEIGHT % < 5 mm
7	41	7	33	PR	12	27.9
3	32	5	50	PR	10	27.0
6	44	6	32	PR	12	35.6
7	45	8	30	PR	10	34.1
3	36	5	42	PR	14	18.5
4	40	4	37	PR	15	17.1
4	38	5	39	PR	14	28.5
4	44	4	40	PR	4	35.1
4	45	3	39	PR	9	43.1
3	42	4	38	PR	13	35.1
3	38	3	43	PR	13	40.4
2	29	3	54	PR	12	26.4
TR	30	7	50	PR	13	35.6
TR	28	9	49	PR	14	36.8
2	32	6	44	PR	16	38.8
4	38	4	40	PR	14	22.5
3	38	5	38	PR	16	25.6
4*	44	4	40	PR	8	68.6
4*	38	3	45	PR	10	63.4
4*	40	3	47	PR	6	81.4

Table 2 - Summary of mineralogy of the less than 5 micron size fraction of Viking Formation X-ray diffraction samples. * Denotes shale samples.

Framework grains within the laminae and lenses are principally quartz with some feldspars. Rock fragments and chert are also present in minor amounts. Quartz is monocrystalline with few inclusions. Grains are equant to subelongate and commonly exhibit subangular, occasionally subrounded outlines.

Both alkali and plagioclase feldspars are present. Alkali feldspars are mainly orthoclase and occasionally microcline, occurring in characteristic tabular habit. Varying degrees of alteration to illite along cleavage planes are evident. These feldspars are occasionally partially dissolved, resulting in secondary porosity. Plagioclase feldspars are commonly of finer grain size than alkali feldspars, and range from albite to andesine in composition. Like alkali feldspars, plagioclase grains exhibt varying degrees of slight to moderate alteration to illite. These grains also exhibit tabular forms. Both types of feldspars show the effects of mechanical compaction, as evidenced by broken grains and curved lamellae.

Rock fragments are predominantly sedimentary and metamorphic in origin, although volcanic fragments are also present. Most rock fragments are shale clasts which exhibit varying degrees of physical deformation. These labile clasts are commonly deformed plastically between and around more competent framework grains. Metamorphic rock fragments are similarly deformed; they comprise both phyllite and schist. Chert grains are also present in minor amounts.

Other grains, which occur in minor to trace amounts, include glauconite and mica. Glauconite occurs locally as mostly fresh subrounded to rounded grains which are slightly (in some instances, moderately) deformed. Micas include both muscovite and biotite. Both types occur as thin, elongate, tabular flakes which are broken or bent by compaction.

X-ray diffraction analysis of the shales that enclose and separate the sandier units shows that they consist principally of illite, smectite, and mixed layer clays, with some quartz and minor amounts of feldspar, kaolinite, and pyrite (Tables 1 & 2).

Diagenesis

Chemical diagenesis can enhance or destroy desirable features of pore systems in sandstones. Chemical diagenesis has resulted in substantial clay, quartz, and feldspar cements, together with minor siderite, dolomite, and pyrite cements which adversely effect reservoir quality. A positive effect of diagenesis is the creation of secondary solution porosity.

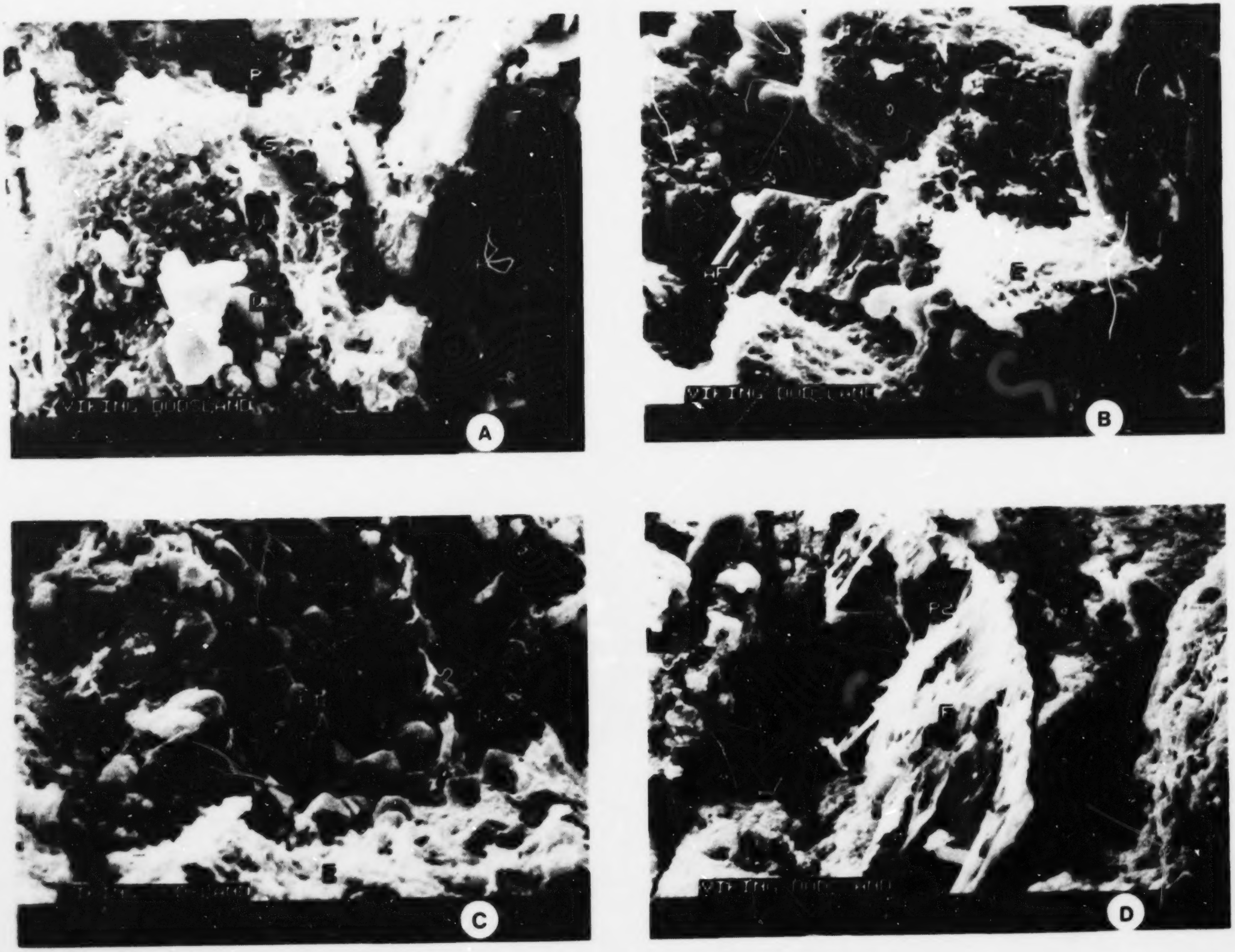
Mechanical compaction of the Viking sediments has resulted in physical adjustment and closer packing of framework grains. The effects of compaction are more prominent in siltstones than in sandstones, as physical deformation of labile clasts occurs to a greater degree. Grains such as rock fragments, mica, and glauconite are all physically deformed around more competent grains.

Framework grains within sand lenses and laminae are moderatley oriented and display curved or long grain contacts. The shales which enclose these laminae and lenses are composed of clay minerals which also show evidence of compaction by their preferred orientation. Detrital grains within these shales exhibit some alignment parallel to stratification. Draping of shale laminae over sandstone and siltstone lenses is also common.

Several types of cement are observed within the samples; these include authigenic clays, quartz, feldspar, pyrite, dolomite, and siderite. Some of these cements are minor in amount and local in occurrence, and therefore influence porosity and permeability less than clay cements.

Authigenic clay minerals include illite, mixed layer illite-smectite, and smectite. Authigenic kaolinite and chlorite are sometimes observed, but identification of these clays is difficult due to the abundance and habit of illite and smectite clays. Illite, illite-smectite, and smectite all occur as authigenic phases as well as detrital clays. The authigenic phases often show reticulate texture with fine filamentous protrusions lining and bridging intergranular pores (Fig. 5a, c, d). Identification of individual clay species by morphology alone is difficult; energy dispersive X-ray analysis (EDS) is required. Even with EDS, positive identification is difficult since each spectrum indicates some elements common to all three clays. Relative abundance of these clays can only be reasonably determined by X-ray diffraction.

Fig. 6 - a). Heavily clay coated grains are common. Identification of smectite (S) is based on morphology and energy dispersive X-ray analysis. Small quartz euhedra (Q) are visible to the left of authigenic smectite. b). Quartz (Q) and feldspar (AF) cements are developed where authigenic smectite (S) has not developed. Intergranular macropores (P) remain in these areas. c). Pyrite (PI) cement occurs in more argillaceous areas where detrital illite-smectite (I-S) are concentrated. Authigenic smectite (S) identified by energy dispersive X-ray analysis occurs on the detrital clays. d). Feldspars (F) show dissolution and alteration resulting in secondary porosity (P2).


P
G
D
VIKING
A
E
B
E
C
P2
F
D

Quartz cement forms incomplete syntaxial overgrowths on quartz grains where detrital illite or smectite grain coatings are absent (Fig. 5b). Because of the widespread development of these clays, quartz overgrowths are irregularly distributed. They do not significantly reduce overall porosity nor permeability, nor do they increase competency of the sands. Feldspar cement only rarely forms as overgrowths; the few examples observed are predominantly on plagioclase. This feldspar cement has only minor, local effects on porosity and permeability (Fig. 6b).

Dolomite and siderite also form local cements composed of very fine subhedral rhombs. Where these aggregates are developed, they may infill one or several intergranular pores. Pyrite cement, like siderite and dolomite, is localized and forms nodules of bipyramidal euhedra concentrated in the more argillaceous areas of sand lenses (Fig. 6c). The minor amount and location of this pyrite does not adversely affect the reservoir quality of the sand.

RESERVOIR QUALITY

The subjective term 'reservoir quality' reflects the physical properties of porosity and permeability. Those properties are controlled by sand content, grain size, grain sorting, clay content, clay type and distribution, and most significantly, by compaction and cementation.

The porosity types now in existence are the results of modification by physical and chemical processes. Deformation of ductile rock fragments and detrital clays results in decreased porosity, and more significantly, permeability. Cementation by clays, quartz, siderite, and pyrite all contribute to modification of the pore system. Porosity types and their classification are central to evaluation of potential reservoir performance. Pittman (1979) noted the importance of basic porosity types on features such as permeability and irreducible water saturation. The role of secondary porosity was developed at length by a number of workers, including Schmidt and McDonald (1979).

Porosity types present in the Viking Formation of the Dodsland area are, in decreasing order of importance: (1) primary intergranular macroporosity; (2) intergranular microporosity associated with detrital and authigenic clays; and (3) secondary porosity derived from feldspar solution.

Intergranular macroporosity is best retained in the cleanest and coarsest sands found towards the top of each of the sandy shale units. Although primary porosity is restricted by detrital clay mineral coatings, the poorly consolidated nature of the sands indicates a low degree of compaction which is accompanied by loose packing and relatively high permeability (Fig. 5a).

Microporosity is associated with the clay minerals. The distribution of these clays significantly effects both porosity and permeability. The clay occurrence model of Wilson and Pittman (1977) is applied in this paper. The most common occurrence of detrital and authigenic clays is pore lining (Figs. 5b, d; Figs. 6a, b). Detrital clays coat most framework grains; they are commonly flocculated, producing a loosely compacted system of micropores. Authigenic clays have formed on the detrital clays, producing a reticulate network with increased surface area, again resulting in significant microporosity. Where grains are in contact, authigenic clays may bridge pore throats, reducing permeability. Authigenic kaolinite and chlorite only rarely form very localized pore linings. These clays generally occur in edge to face habit with respect to grain surfaces, again creating micropores.

Secondary porosity is locally developed by partial feldspar dissolution. The intragranular nature of this porosity only slightly adds to total permeability. However, the overall effect of secondary porosity on reservoir quality is directly proportional to feldspar content.

CONCLUSIONS

Detailed examination of core petrographic studies of producing intervals from the Viking Formation in the Dodsland area allow a number of conclusions to be made regarding reservoir quality:

1. The productive interval consists of two essentially similar, slightly coarsening upwards shaly sands which are typically separated by approximately 1 m of shale. Sands of better reservoir quality are concentrated towards the top of these sandy units.
2. Mineralogy of the sandstones remains quite consistent over a reasonably large area. Quartz and feldspar are the predominant framework grains, with illite, smectite, and mixed layer illite-smectite the dominant clays. Kaolinite and chlorite are present in minor amounts in all samples, with dolomite, siderite, and pyrite locally developed.
3. Communication between sand lenses is via microporous, low permeability shales which enclose the more porous and permeable sands, creating vertical and horizontal permeability barriers.
4. Clay mineralogy is central to reservoir quality and to potentially damaging rock-fluid interactions that may take place under normal drilling, completion, and producing conditions. These interactions include fresh water sensitivity of smectite and illite-smectite clays, and fines movement. If these occur separately or in combination, they are likely to result in large scale permeability reduction. Both these mechanisms have been observed in laboratory tests for similar samples from the Viking Formation in this area.

ACKNOWLEDGEMENTS

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CRETACEOUS OIL SHALE POTENTIAL IN SASKATCHEWAN[1]

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ABSTRACT

Four hundred forty-seven samples, obtained from cores and potash shafts penetrating the oil shale beds of the Upper Cretaceous Boyne and Favel Formations (1st and 2nd white speckled shale zones, respectively) at 29 locations across the Prairie Provinces, were analyzed for total organic carbon and subjected to Rock-Eval pyrolysis. Of these, 382 samples from Saskatchewan and Manitoba were analyzed mineralogically by X-ray diffraction.

Both oil shale zones are thermally immature, and have not been petroleum source rocks in Saskatchewan, although biogenic gas has been generated and trapped in the southwestern corner of the Province. Samples everywhere contain some Type III humic kerogen, possibly up to 4 per cent; above that, total organic carbon values ranging to 10 per cent are created by the addition of Type II sapropelic kerogen. Hydrocarbon yields on pyrolysis increase proportionately from 3.0 kg/t/1% TOC in the humic areas to 6.5 kg/t/1% where sapropel predominates.

Two areas of optimum hydrocarbon yield can be mapped in the Pasquia Hills at the east, and from limited data, along the outcrop area of western Saskatchewan. In both areas, TOC average values may range up to 10 per cent with average hydrocarbon yields anticipated in excess of 40 kilograms/tonne (10 U.S. gallons/ton) from both the Boyne and Favel Formations. Kerogen distribution appears to be fairly uniform vertically in Boyne beds along the norther slope of the Pasquia Hills.

Lithologically similar, both oil shale zones contain inversely related proportions of a quartz-clay-feldspar mode and a calcite dominated mode. Kerogen content is at a maximum when modes are essentially equal, or where calcite dominates slightly, but decreases as pure limestone is approached. Numerous secondary minerals are present, many of which are hydrated and vary only by degree of hydration. High water content may hinder retorting techniques and purer carbonate lenses may also require separation from the main ore if mined.

INTRODUCTION

Tyrrell (1892) first reported the presence of possible oil shales along the Manitoba Escarpment as he described the petroliferous odour emanating from the rocks when struck by a hammer. McInnes (1913) listed the first analysis: 7 Imperial gallons/ton (35 l/t) with 22.5 lbs ammonium sulphate/ton (11.2 kg/t). The first significant geological comment came from S.C. Ells (1923), who stated "Oil shales of New Brunswick and Nova Scotia were deposited under different conditions from those of Manitoba and Saskatchewan". Although not stated specifically, Ells did understand that the depositional environment was a marine "muddy sea" in the Manitoba-Saskatchewan area in contrast to the lacustrine environment of the New Brunswick oil shales. Ells also noted that the "oil" content of the Manitoba beds did not prevent weathering in contrast to the resistive nature of the Maritime shales.

Two oil shale zones are present along the Manitoba Escarpment, an upper in the Boyne Formation and a lower in the Favel Formation, which are separated by a non-oil shale interval, the Morden Formation. Both zones are similarly composed of white speckled shale with foraminiferal debris and coccoliths comprising the white specks. The three units are traceable across the three prairie provinces, except for a central area of Saskatchewan where the medial Morden Formation is poorly defined to absent, resulting in an apparent single specked shale unit (Fig. 1). Withing the subsurface of Alberta and western Saskatchewan, these zones are informally defined as the First and Second White Speckled shale zones (Fig. 2).

This paper is excerpted and modified from the author's unpublished report "Cretaceous Oil Shale Potential of the Prairie Provinces, Canada", Geological Survey of Canada Open File Report OF977, and focusses primarily on the organic geochemistry of the oil shales, as determined analytically, from samples collected from four coreholes in Manitoba, 20 subsurface well cores and two potash shafts in Saskatchewan and four subsurface cores in Alberta (Fig. 3). Analytical data are also available from 40 Sun Oil coreholes (1966) located along the Manitoba Escarpment; these cores were subsequently destroyed and are no longer available.

The analytical techniques utilized total organic carbon (TOC) analysis and Rock-Eval pyrolysis for determination of organic content, and X-ray diffraction for mineral content. Fischer Assay data are available for the lost Sun Oil cores.

STRATIGRAPHY

Nomenclature history for the Manitoba Escarpment and the subsurface of Manitoba and Saskatchewan is relatively straightforward, although not without complications. Early oilfield terminology has been retained in the Alberta and western Saskatchewan subsurface where the "White Specks" zones and adjacent lithologies are still not properly defined (Fig. 2): no need has been felt for formal nomenclature.

Ells (1923) first used the term "Boyne" to refer to the white speckled shale zone which was faunally equated to the niobrara Formation of the United States sections to the south Because of this stratigraphic equivalence, McNeil and Caldwell (1981) recommended use of the earlier defined Niobrara in preference to Boyne; however, because of widespread usage in Canadian publications, government correlation charts and files, and throughout the petroleum industry, Boyne is retained even though Niobrara has nomenclatural priority.

Beds of the Favel Formation have been subdivided into the Assiniboine and Keld Members (Wickenden, 1945) within which significant carbonate bands are recognized (Marco calcarenite and Laurier limestone; McNeil and Caldwell (1981). Because organic carbon is present throughout the Favel

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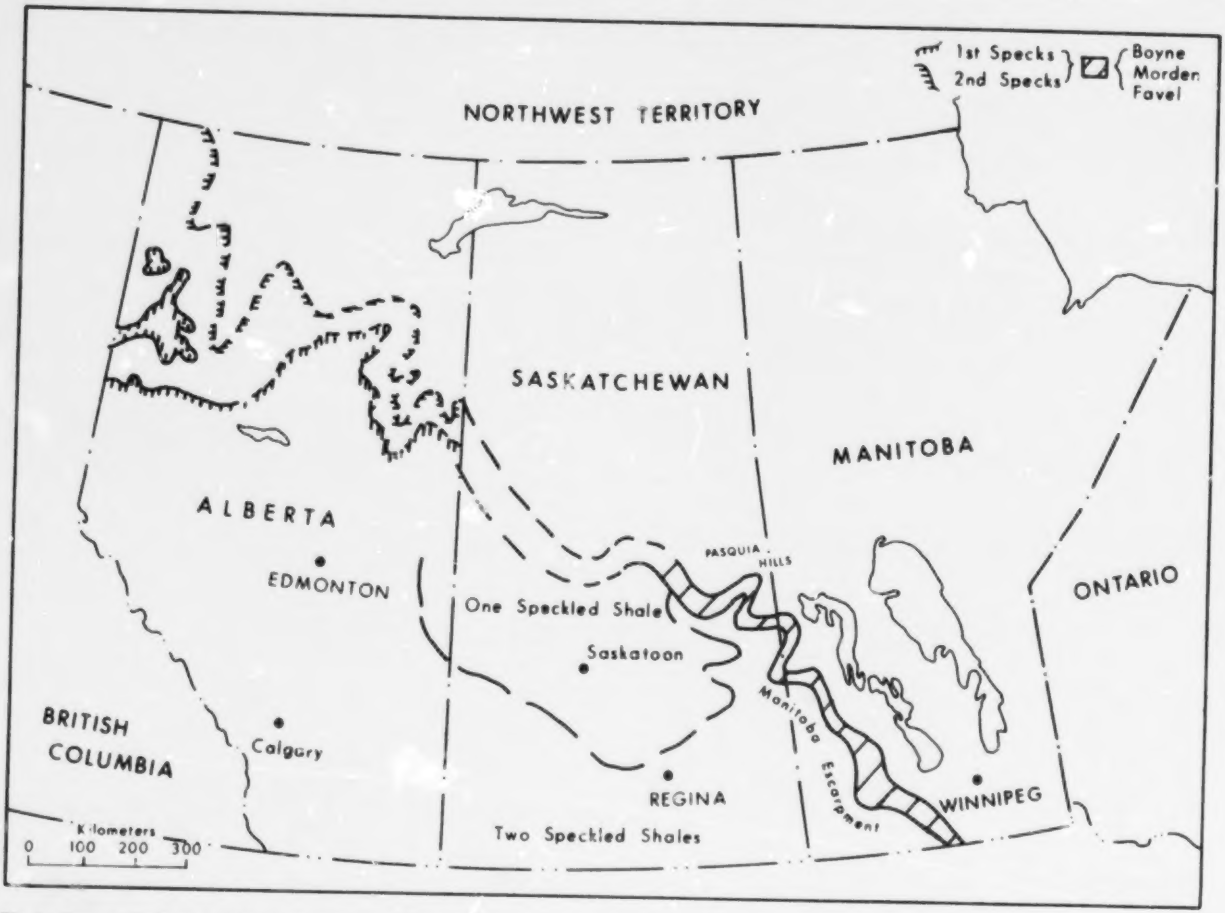
1st Specks
2nd Specks
Boyne
Morden
Favel
NORTHWEST TERRITORY
SASKATCHEWAN
MANITOBA
ALBERTA
EDMONTON
PASQUIA HILLS
One Speckled Shale
Saskatoon
ONTARIO
BRITISH COLUMBIA
Calgary
Manitoba Escarpment
REGINA
WINNIPEG
Two Speckled Shales
Kilometers
0 100 200 300

Fig. 1 - Outcrop distribution of Upper Cretaceous oil shale zones in the prairie provinces.

Simpson 1981				This Paper	McNeil & Caldwell 1981	
SW Sask		SE Sask – SW Man				
PAKOWKI		RIDING MOUNTAIN		RIDING MOUNTAIN	Pierre Shale	
MILK RIVER		VERMILION RIVER	Pembina	PEMBINA		
COLORADO GROUP	Medicine Hat Ss. First Speckled Shale		Boyne	BOYNE	NIOBRARA	
	Shale		Morden	MORDEN	MORDEN	
	Second Speckled Shale	FAVEL	Assiniboine	FAVEL	FAVEL	Assiniboine
			Keld			Keld
	Shale	ASHVILLE		ASHVILLE	Belle Fourche Shale	

Fig. 2 - Pertinent Upper Cretaceous stratigraphy (Formations in capitals; members and sub-units in lower case).

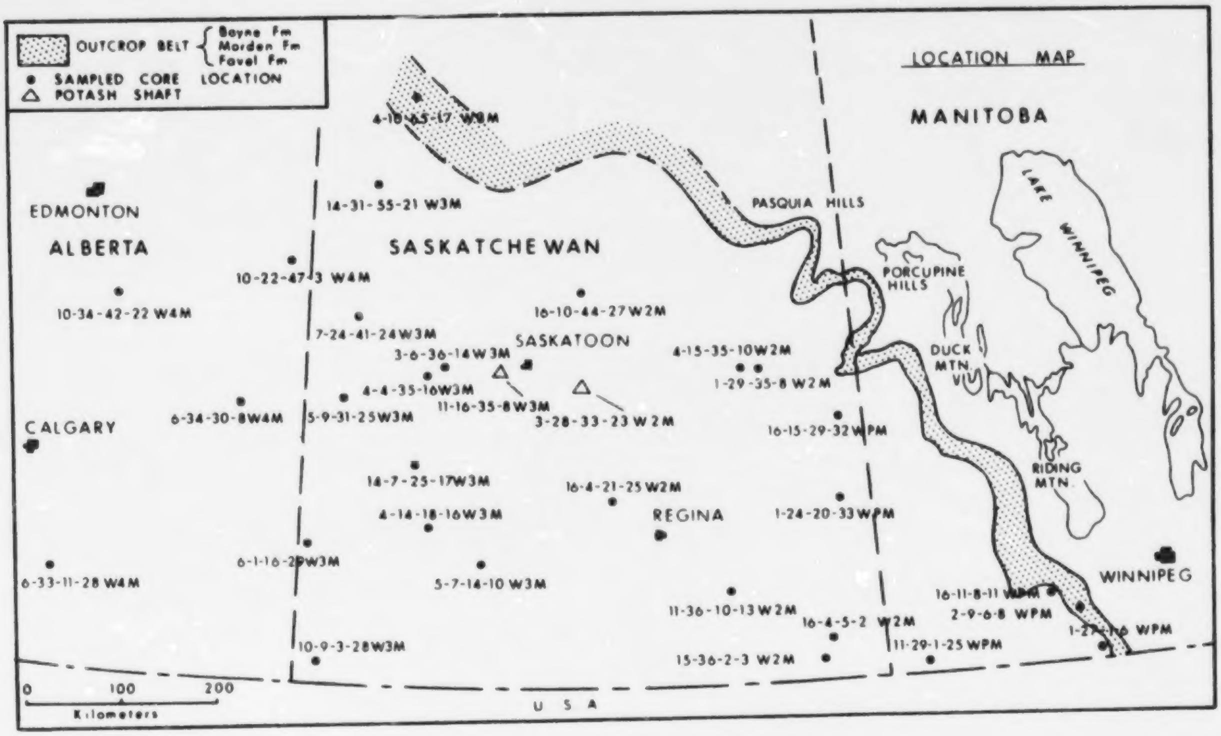
OUTCROP BELT
Boyne Fm
Morden Fm
Favel Fm
SAMPLED CORE LOCATION
POTASH SHAFT
LOCATION MAP
MANITOBA
LAKE WINNIPEG
EDMONTON
ALBERTA
SASKATCHEWAN
CALGARY
SASKATOON
REGINA
WINNIPEG
PASQUIA HILLS
PORCUPINE HILLS
DUCK MTN.
RIDING MTN.
4-10-65-17 W3M
14-31-55-21 W3M
10-22-47-3 W4M
10-34-42-22 W4M
16-10-44-27W2M
7-24-41-24W3M
3-6-36-14W3M
4-15-35-10W2M
1-29-35-8 W2M
4-4-35-16W3M
11-16-35-8W3M
3-28-33-23 W2M
6-34-30-8W4M
5-9-31-25W3M
16-15-29-32 WPM
14-7-25-17W3M
16-4-21-25 W2M
4-14-18-16W3M
1-24-20-33WPM
6-1-16-29W3M
5-7-14-10 W3M
6-33-11-28 W4M
11-36-10-13 W2M
16-4-5-2 W2M
16-11-8-11 WPM
2-9-6-8 WPM
1-27-1-6 WPM
11-29-1-25 WPM
10-9-3-28W3M
15-36-2-3 W2M
0
100
200
Kilometers
U S A

Fig. 3 - Core and potash shaft sample localities.

Formation, no attempt is made to define these sub-units for this regional geochemical evaluation.

Park (1965) illustrated the westerly thinning of the intervening Morden shale in Saskatchewan to outline an area where only one speckled shale unit is readily apparent (Fig. 1). Within this area, thin beds of probable Morden strata can often be picked on geophyical logs and confirmed by geochemical analyses. The Boyne/Morden speckled shale/non-organic shale sequence is macroscopically identical to the Favel/Ashville sequence; however, Boyne and Favel strata can be differentiated by micropaleontology (Park, 1965; North and Caldwell 1975; McNeil and Caldwell, 1981).

LITHOLOGY

Both oil shale zones consist of identical lithologies: dark to medium grey to brownish-grey shale, with a variable degree of white speckling by coccolithic and possible foraminiferal debris. The shales are finely laminated to fissile, but fissility decreases as carbonate content increases toward pure limestone. The calcareous shales grade to marls where fossil debris becomes the dominant rock component.

Bands of non-calcarous shale, barren of fossil debris, are present within the speckled intervals. Also, beds of non-calcareous shale, normally included within the overlying and underlying stratigraphic units, may contain significant organic carbon and are here included within the Boyne and Favel intervals; consequently, geochemically defined limits may differ slightly from those based on calcareous distribution and/or geophysical log characteristics.

THICKNESS

The Boyne Formation ranges in thickness from 30 to 45 m along the Manitoba Escarpment, thins to approximately 15 to 18 m in central Saskatchewan where it is contiguous with the Favel beds, and thickens again to a range of 35 to 60 m in the Alberta subsurface.

The Favel beds attain a general maximum thickness of 30 to 40 m along the Escarpment, thin westerly to only a few metres in central Saskatchewan, and again thicken to 35 to 60 m in the subsurface area of Alberta.

The intervening Morden Formation thins westerly from 45 m at the eastern outcrops to essentially zero in central Saskatchewan and thickens to more than 100 m of unnamed beds in the Alberta subsurface and 300 m in the Alberta Foothills belt. Park (1965) illustrated these relationships in regional correlation sections across Saskatchewan.

MINERALOGY

X-ray diffraction (XRD) analyses are available for all Manitoba and Saskatchewan samples; however, samples from the four Alberta cores were not analyzed. Complete XRD data are available in Macauley (1984).

From the XRD results, several mineral suites are recognized: two of these represent the primary minerals, and the remainder are secondary.

PRIMARY MINERAL MODES

A quartz-clay-feldspar grouping defines the majority of the rock as a shale, in the sense of a fine grained laminated clay

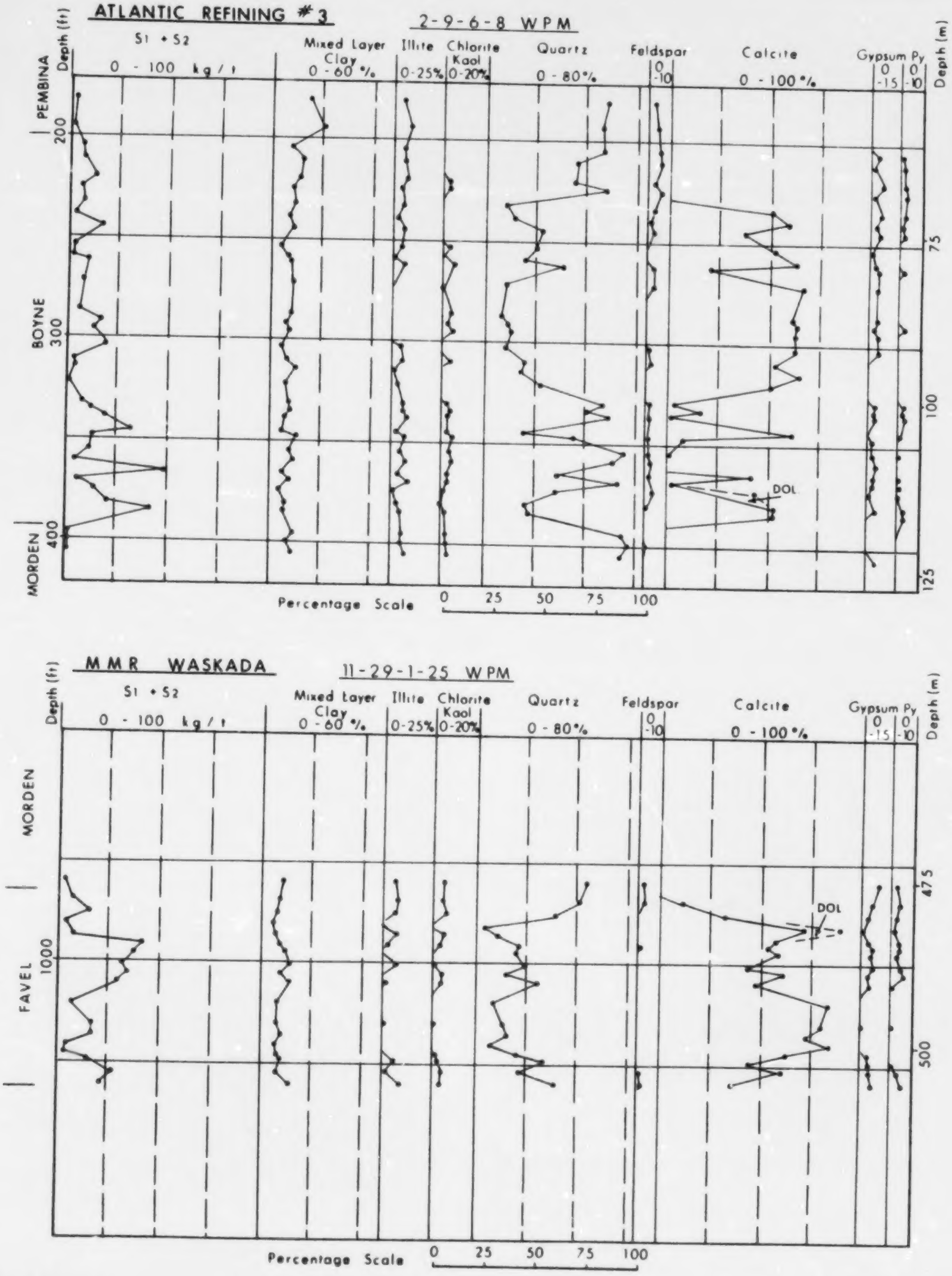

Fig. 4 - Typical distribution plots of primary mineral components; a) Boyne Formation; b) Favel Formation.

sediment. Quartz is the dominant member; clays are significant and present as mixed layer clays, illite and chlorite-kaolinite in order of decreasing percentages; feldspars are recorded only in minor amounts and are often absent (Figs. 4a, 4b).

Calcite, with minor dolomite, is the second major mineral mode; the occurrence of calcite is in an apparent proportional inverse ratio to the quartz-clay-feldspar consituents (Figs. 4a, 4b). Occasional dolomite is present only as a trace to a few per cent. In effect, most of the oil shale beds are calcareous shale grading to argillaceous limestone; however, non-calcareous shales may be organic, especially at the top of the Boyne (Fig. 4a).

The inter-relationship of quartz-clay-feldspar and calcite may be economically significant. Figures 5a and 5b are plots of the hydrocarbon potential ($S_1 + S_2$) against the recorded percentage of calcite. The scatter of points indicates that no direct correlation, on a single value basis, can be made for hydrocarbon potential and mineral content; but average values indicate maximum yields at approximately 40% calcite in the Boyne Formation and 60% calcite in the Favel Formation. As calcite content increases toward pure limestone, hydrocarbon potential decreases markedly (Fig. 4b). The number of points plotted along the zero calcite line indicates the presence of a considerable amount of kerogen-bearing non-calcareous shale (Fig. 5a).

SECONDARY MINERAL MODES

Secondary minerals can be arranged in several distinct groups with some minerals, especially those with significant Fe content, being reportable in two groups.

Zeolites

These hydrous silicates of Ca, Mg, Al, K, Na and Fe are present in small amounts throughout the two oil shale zones, the intervening Morden and equivalent shale beds, and also in the uppermost portion of the underlying Ashville and equivalent shales. Zeolites include clinoptilolite, analcime, loughlinite, heulandite, laumontite and palygorskite. Because of the minimal feldspar content, the zeolites may represent the *in situ* destruction of the feldspars during sedimentation and lithification.

Non-hydrous silicates

In contrast to the zeolites, some non-hydrous silicates are present, including amphibole, biotite and hydrobiotite, chlorite, and diopside. These may be in part detrital minerals or may be the altered products of detrital feldspar and mafic minerals.

Phosphates

Phosphate minerals are uncommon, but represent a sequence from complex (millisite and apatite) to simpler (strengite) structures, containing the same basic metallic elements as encountered in the zeolites, but including Fe. Two of the three forms are hydrated.

Sulfates

Nine sulfates are present, also with a wide range of elemental composition, and include jarosite, natrojarosite, alunite, bassanite, gypsum, barite, epsomite, rozenite and melanterite. Analogous to the zeolites, Na, K, Ca, Mg and Al are the basic elements but with the addition of Fe. Also notable is the presence of minerals with similar compositions except for differing degrees of hydration.

Gypsum is the most prominent sulfate and appears to be distributed generally within the same zones in which pyrite is present. Free sulfur crystals were noted visually in association with gypsum crystals. The pyrite is a probable source of the sulfur required to form sulfate minerals.

Carbonates

In addition to calcite and dolomite, ankerite, dawsonite, and nesquehonite indicate possible alteration of some of the zeolite minerals to carbonates.

Fe Minerals

Pyrite is the most common iron mineral; it is almost ubiquitous. Pyrite decreases, and is often absent, in the most calcareous beds. Fe is also present with sulfur as greigite, and occurs in a series of sulfates (jarosite, natrojarosite, melanterite, rozenite), as oxides (hematite, goethite, lepidocrocite, maghemite, magnetite) and in one phosphate (strengite). Many of the oxide and sulfate forms differ only in degree of hydration, although differences in Fe valency are also significant.

Oxides

Several of the oxides were reported among the iron minerals (goethite, lepidocrocite, hematite, maghemite and magnetite). Tridymite and cristobalite are probable detrital minerals whereas gibbsite, bayerite and diaspore may be oxidation products of the feldspars and zeolites.

INTERPRETATION

When were the secondary mineral suites, especially the sulfates and the oxides, generated? Are these the result of sedimentation and lithification processes or has exposure to the atmosphere resulted in oxidation of the core material? Most of the cores are in excess of 15 years old, but some cores from southwest Manitoba have been encased in plastic during that time. The organic material and the pyrite represent a reducing environment; how has the organic material been preserved during formation of the oxides and sulfates?

Zeolites, of inferior hardness (3.5-5.5), are unlikely detrital minerals, and are inferred to have formed *in situ* by chemical alteration, primarily hydration, of detrital feldspars. The zeolites contain Na, K, Ca, Mg, Al, Si, all of which are represented in virtually all the other secondary sequences. Zeolites are destroyed by acid: sulfuric or sulfurous acid can be generated by oxidation of pyrite, which, acting on the zeolites, would provide many of the sulfates and some of the complex carbonates and phosphates. In all of the secondary mineral groups, transitions to smaller molecular structures and enrichment in Fe, S and O are apparent.

Water of crystallization is common to all of the secondary groups, in some cases defining several minerals with otherwise identical compositions. These rocks have probably not been subjected to sufficient depths of burial to have generated the heat and pressure necessary to expel this water.

Although no conclusion can be reached, the abundance of these secondary minerals, and the commonly sequential distributions of the cations within them, may be indicative of depositional - lithification processes rather than weathering during the last few years.

Ells (1923) noted the poor resistance of these beds to weathering in contrast to other oil shales. The presence of many easily altered hydrous minerals may account for this characteristic.

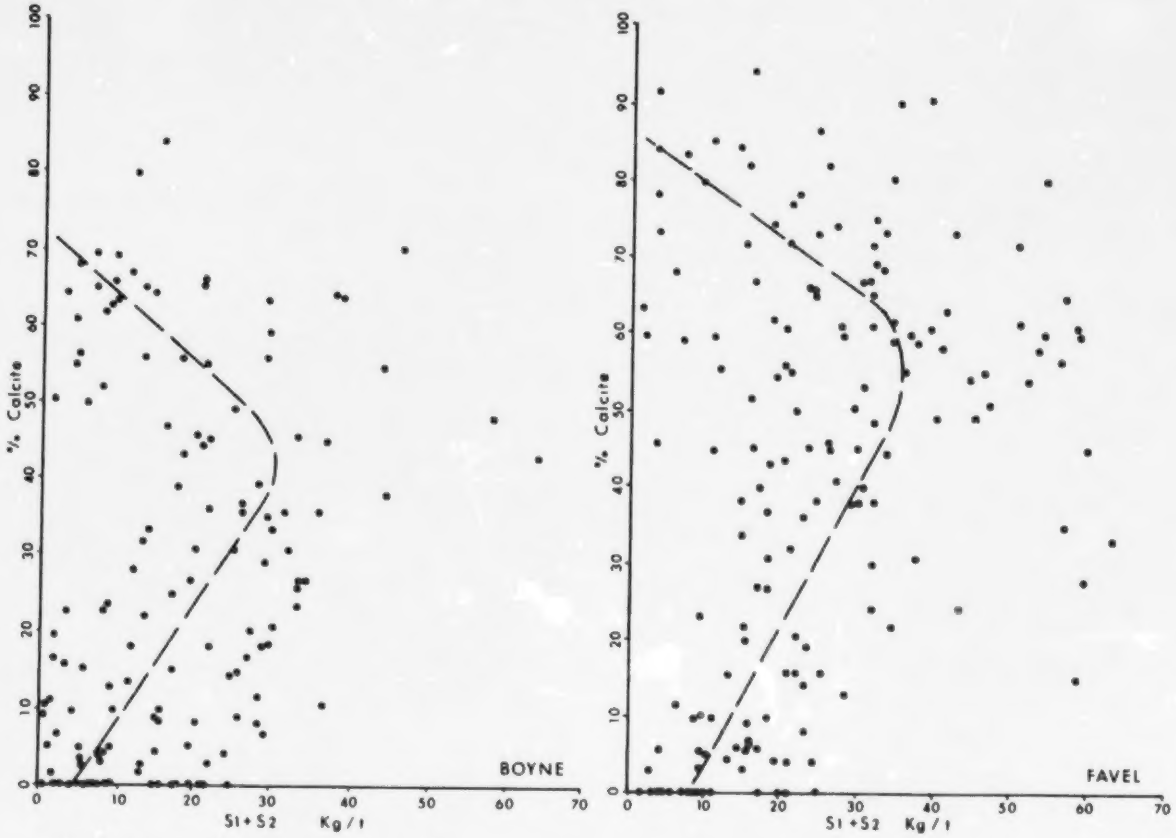

Fig. 5 - Approximate calcite content from XRD plotted against hydrocarbon yield: a) Boyne Formation; b) Favel Formation.

ORGANIC GEOCHEMISTRY

All data from the analyses of total organic carbon and Rock-Eval pyrolyses are described, or appended, in the Geological Survey of Canada Open File Report OF977 (Macauley, 1984). Data plots for two southwestern Manitoba locations, 2-9-6-8WPM (Boyne Fm.) and 11-29-1-25WPM (Favel Fm.), have been selected for illustrative purposes here because of the large number of sample points from these coreholes.

ORGANIC MATURATION

T_{max} values vary in the range 405 to 425° C (Figs. 6a, 6b). These are all below the oil generation window (435-465 °C), and therefore indicate organic immaturity. An average T_{max} was calculated for each location; these values increase slightly from 410 to 420° north to south over Saskatchewan. Low maturity (440 °C) is encountered only in southwestern Alberta (Fig. 3, 6-33-11-28W4M).

Immaturity is also indicated by the plots of hydrogen against oxygen indices (Figs. 7a, 7b). Although values vary considerably for the hydrogen indices, oxygen is not lost as hydrogen decreases; consequently the distribution of points reflects variable kerogen components rather than maturation changes.

KEROGEN TYPE

An admixture of Type II and Type III kerogens can be interpreted from the hydrogen-oxygen distribution (Figs. 7a, 7b). The relative position between the Type II and Type III van Krevelen lines has been assumed to represent approximate relative amounts of each kerogen type. An interpretation of these values is presented with the log plot of Rock-Eval data (Figs. 6a, 6b). Hydrogen indices increase with increasing Type II content; total organic carbon and hydrocarbon potential also increase commensurately. Specific low T_{max} values reflect the higher Type II content with T_{max} increasing as Type III kerogen increases. These relationships hold throughout the area.

HYDROCARBON POTENTIAL

The hydrocarbon (petroleum) potential derived by pyrolysis directly relates to the hydrogen index and total organic carbon values. They hydrocarbon yield/1% organic carbon is a significant figure for economic evaluation; the relationship is illustrated by plotting the petroleum potential ($S_1 + S_2$) against total organic carbon (Figs. 8a, 8b). This relationship is not first order linear as indicated by a curve of the average line. The Favel average line (Fig. 8b) shows a break in slope at 3 to 4% organic carbon, beyond which the yield is higher. This, in combination with the HI/OI plots and the T_{max} variations, is interpreted as a reflection of the varying distributions of Type II and Type III kerogens. All sampled locations show a similar

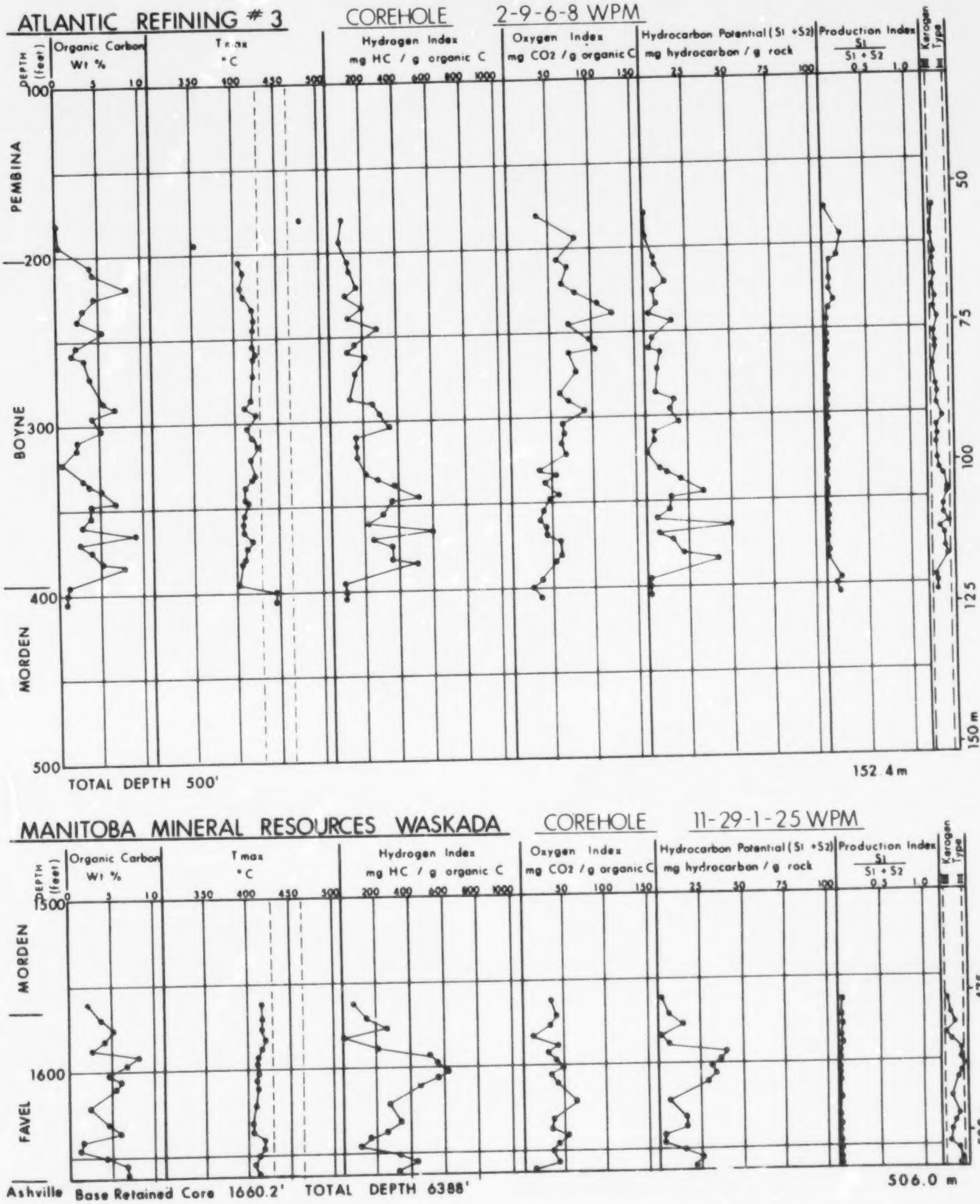

Fig. 6 - Typical plots of total organic carbon and Rock-Eval data: a) Boyne Formation; b) Favel Formation.

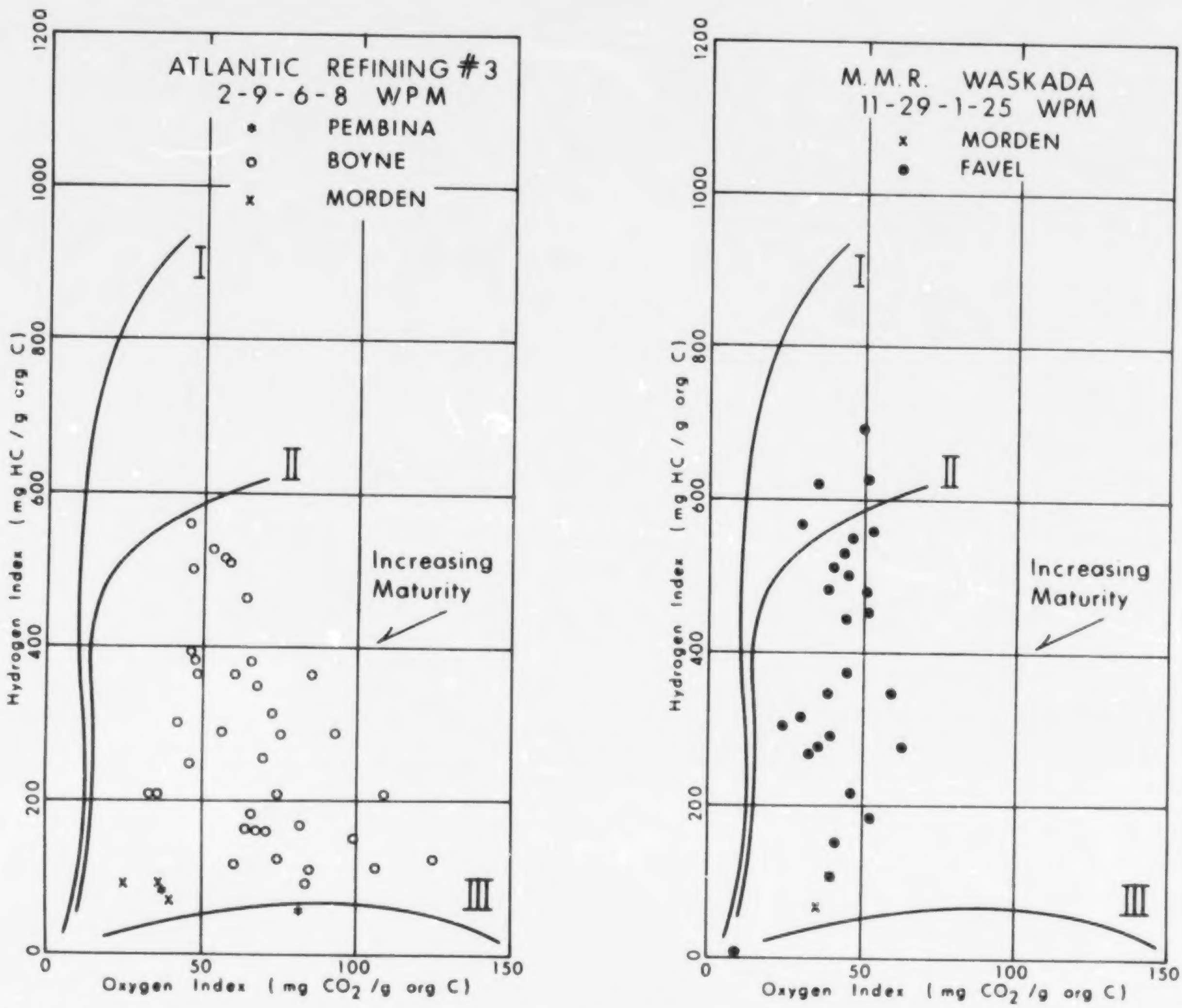

Fig. 7 - Typical plots of hydrogen index (HI) against oxygen index (OI); a) Boyne Formation; b) Favel Formation.

change of slope. The entire area is considered to contain an average of 3 to 4% organic carbon derived from Type III humic kerogen within the organic beds: zones with lesser organic carbon may contain almost entirely humic material: where organic carbon execeeds 3 to 4%, the increase results from the presence of Type II sapropel, and higher hyrocarbon recoveries reflect this change of kerogen.

Average yields per 1% organic carbon range from 3.5 to 4.5 kg/t over the total interval of either oil shale unit, but increase within the units to beds yielding up to 6 kg/t where Type II kerogen predominates.

ECONOMIC POTENTIAL

Any potential for economic oil shale development will depend on the distribution of total organic carbon and the ultimate hydrocarbon yields relative to the organic carbon content.

Data for each location were averaged for Boyne and Favel Formations for total organic carbon (Figs. 9a, b) and for average hydrocarbon yield ($S_1 + S_2$) (Figs. 10a, b). Fewer data points are available for the Boyne than the Favel, but similar geographic patterns of low carbon-poor yield and higher carbon-better yield areas are readily apparent.

Two areas of better potential are recognized, one trending northerly in the eastern part of Saskatchewan, and a second trending northeast along the Alberta-Saskatchewan border, separated by a low potential area trending north-northeast through Saskatoon.

From these maps, the area in the northwest along the outcrop trend in Saskatchewan should be economically interesting, but some caution must be advised as the three key control points contain only a few analytical values which may have been selected from higher yields beds. At 16-10-44-27W3M and 14-31-55-21-W3M (Figs. 9b, 10b; data shown in brackets), one and two samples respectively were analyzed. At the most northerly control point, 4-10-65-17W3M, two analyses provide the Boyne average, and three the Favel data. Nevertheless, the trend appears valid

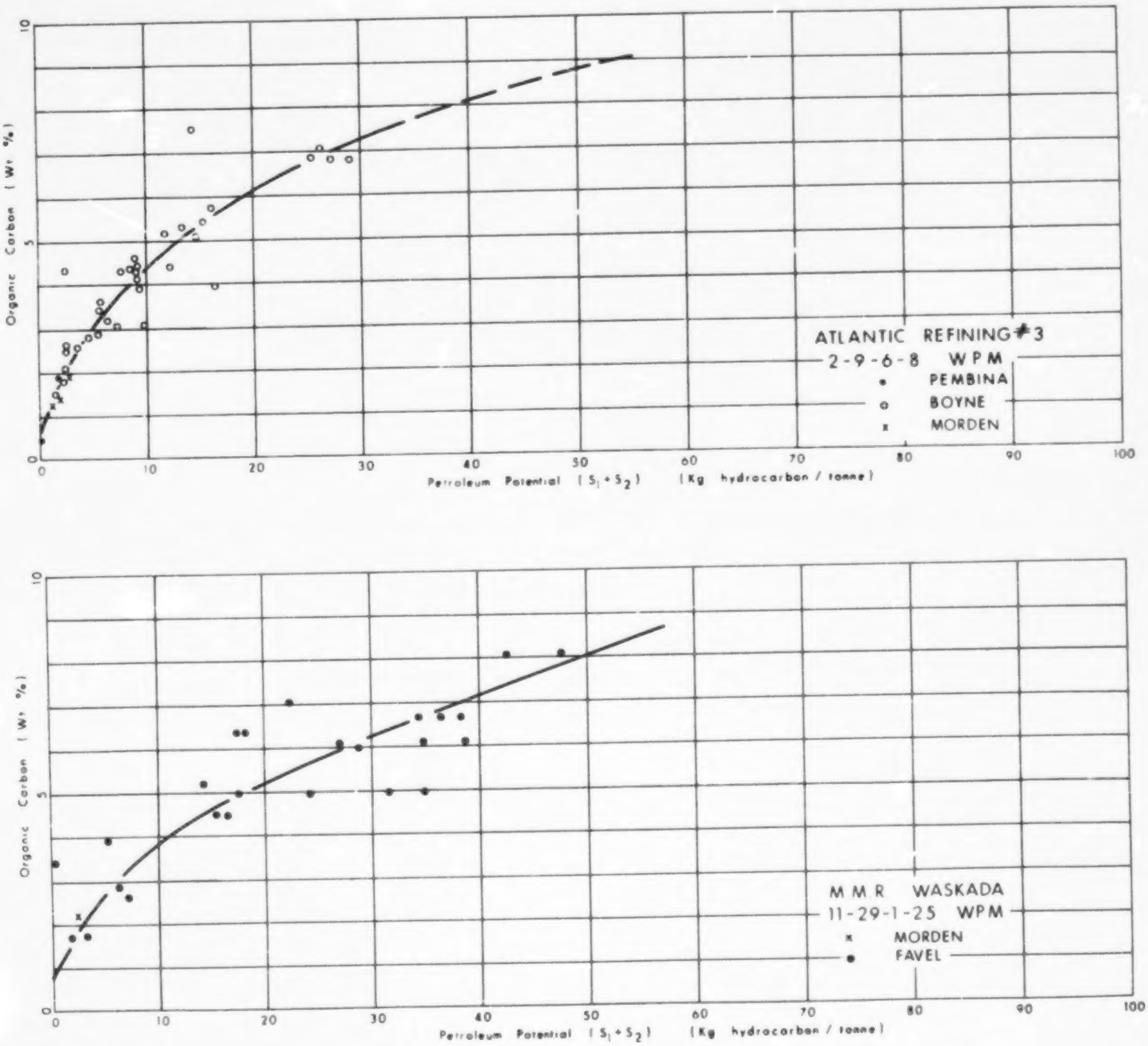

Fig. 8 - Typical plots of total organic carbon against hydrocarbon potential: a) Boyne Formation; b) Favel Formation.

from other data. Drift cover in this area will inhibit evaluation and mining.

The easterly trend is currently of more interest because of the Fischer Assay data available from the Sun Oil core program of 1964-1965 in the Pasquia Hills and Porcupine Hills (Fig. 3). These analyses are on file at the Saskatchewan Geological Survey.

Elevations on the base of the oil shale unit were calculated from the Sun Oil data, as defined by oil yields: most of these elevations appear regionally compatible and are mapped herein as contours on the top of the Morden Formation (Fig. 11). Four values, one at the east end of the Porcupine Hills, one at the eastern extremity of the Pasquia Hills, and two at the east of Duck Mountain, are approximately 100 to 150 feet (30 to 45 m) low relative to the Morden contours; consequently, these cores are interpreted to have penetrated the Favel Formation. Irregularities of the contours on the north flanks of the Pasquia and Procupine Hills reflect distribution of organic material downward in the section. Based on organic content, the Boyne-Morden contact is in part a lateral facies relationship.

Because oil gravities (generally 0.965 in this area) are known, Fischer Assay yields have been converted to kg/t (Fig. 12). An area of optimum yield, in the range 40 to 50 kg/t from the Boyne Formation, is mapped on the north flank of Pasquia Hills, with recoveries decreasing both east and west of the optimum area. These detailed trend lines and data have been incorporated into the more regional hydrocarbon yield maps of both the Boyne (Fig. 10a) and Favel (Fig. 10b) Formations. As contoured, the north slope of the Pasquia Hills is the most attractive area for oil shale development along the Manitoba Escarpment. This is in agreement with Beck (1974).

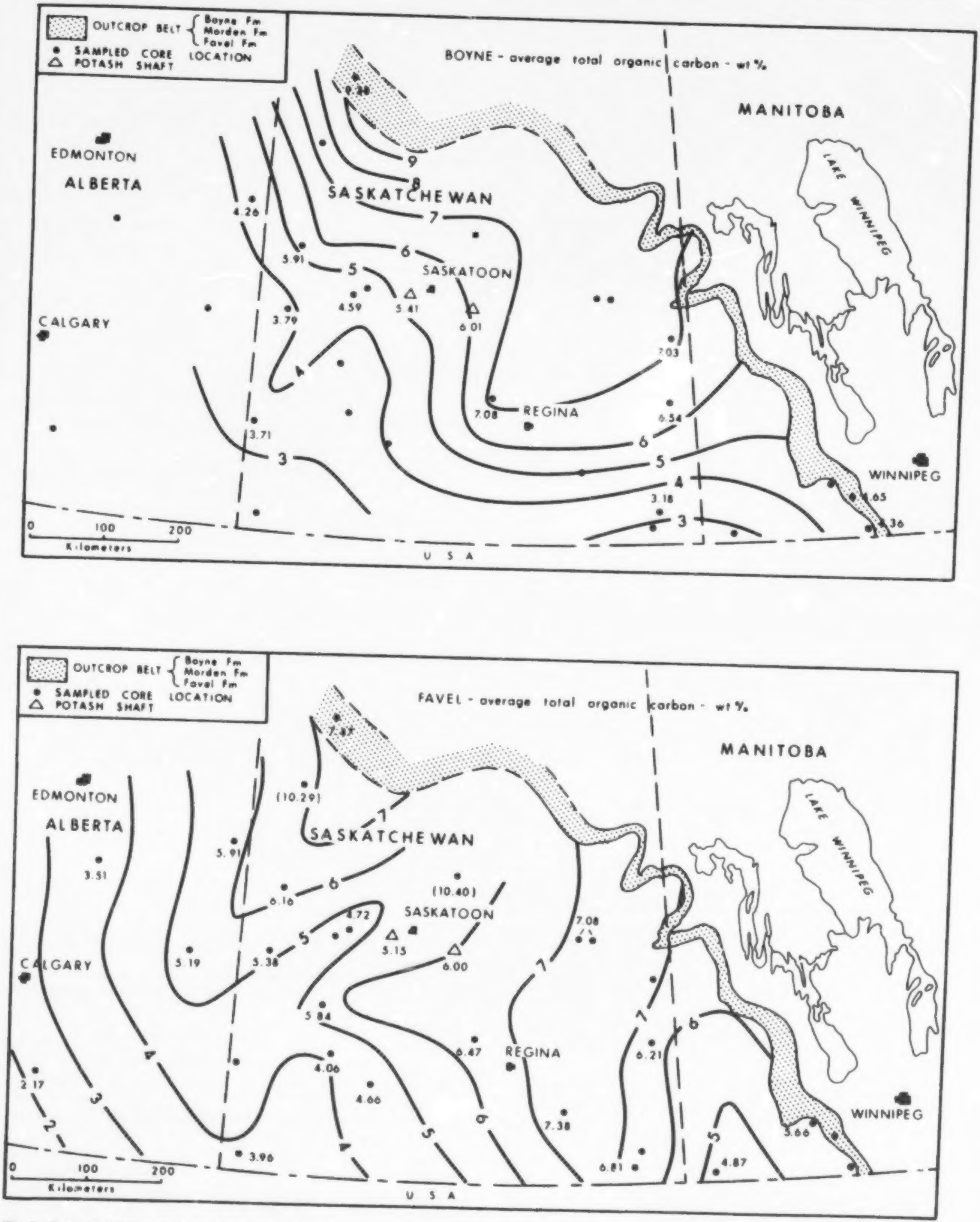
OUTCROP BELT
Boyne Fm
Morden Fm
Favel Fm
SAMPLED CORE LOCATION
POTASH SHAFT
BOYNE - average total organic carbon - wt %
MANITOBA
LAKE WINNIPEG
EDMONTON
ALBERTA
SASKATCHEWAN
SASKATOON
CALGARY
REGINA
WINNIPEG
U S A
0
100
200
Kilometers
9.28
4.26
5.91
3.79
4.59
5.41
6.01
7.03
7.08
6.54
3.71
3.18
4.65
4.36
9
8
7
6
5
4
3
FAVEL - average total organic carbon - wt %
7.47
(10.29)
5.91
3.51
6.16
(10.40)
4.72
5.15
6.00
7.08
5.19
5.38
5.84
6.47
6.21
2.17
4.06
4.66
7.38
3.96
6.81
4.87
5.66
7
6
5
4
3
2

Fig. 9 - Regional distribution of average total organic carbon content: a) Boyne Formation; b) Favel Formation.

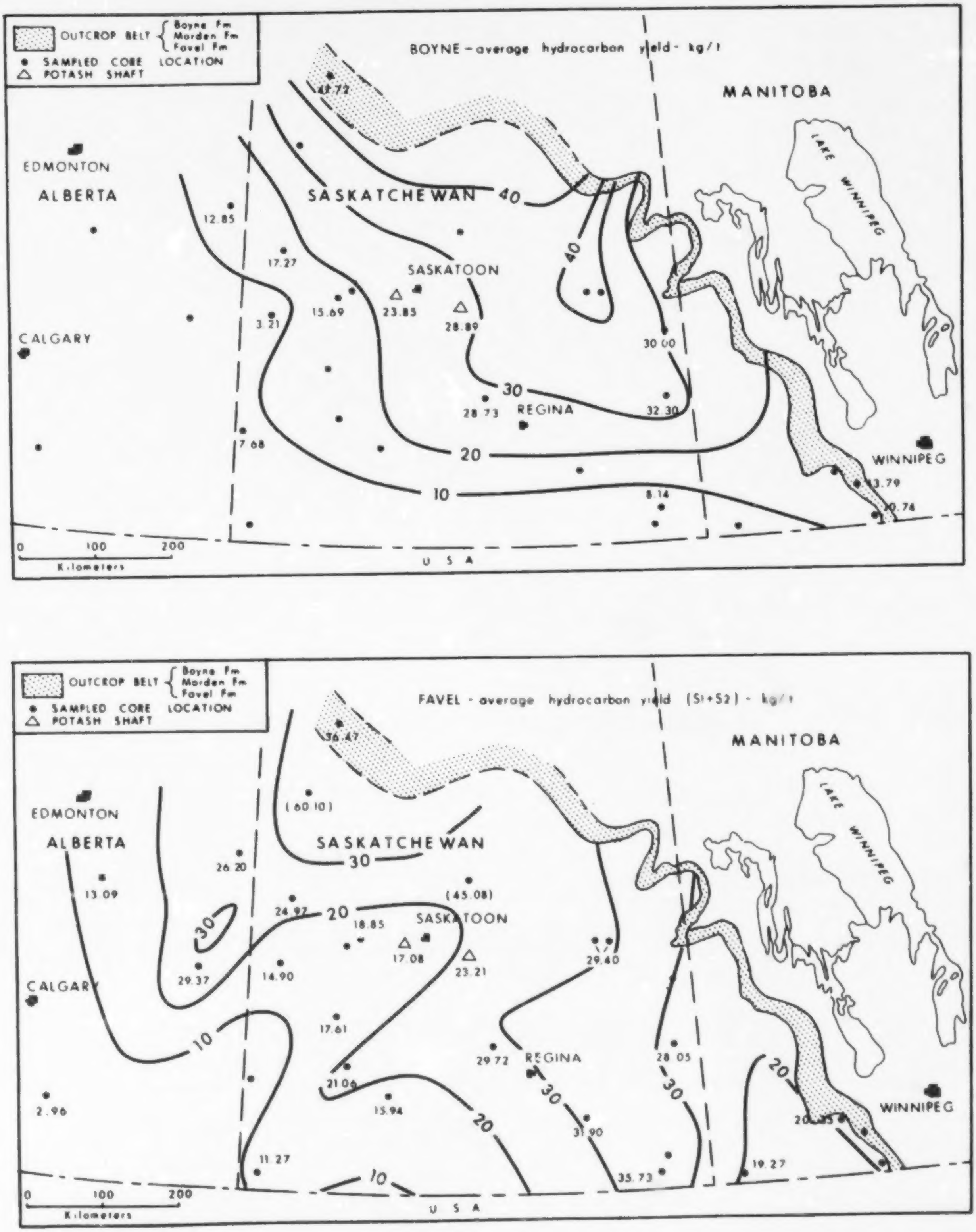
OUTCROP BELT
Boyne Fm
Morden Fm
Favel Fm
SAMPLED CORE LOCATION
POTASH SHAFT
BOYNE – average hydrocarbon yield – kg/t
MANITOBA
LAKE WINNIPEG
EDMONTON
ALBERTA
SASKATCHEWAN
SASKATOON
CALGARY
REGINA
WINNIPEG
47.72
12.85
17.27
15.69
23.85
28.89
3.21
30.00
28.73
32.30
7.68
8.14
13.79
20.74
40
30
20
10
0
100
200
Kilometers
U S A
FAVEL – average hydrocarbon yield (S1+S2) – kg/t
36.47
(60.10)
26.20
13.09
24.97
18.85
(45.08)
17.08
23.21
29.37
14.90
29.40
17.61
29.72
28.05
21.06
15.94
2.96
31.90
20.35
11.27
35.73
19.27

Fig. 10 - Regional distribution of averaged hydrocarbon yields: a) Boyne Formation; b) Favel Formation.

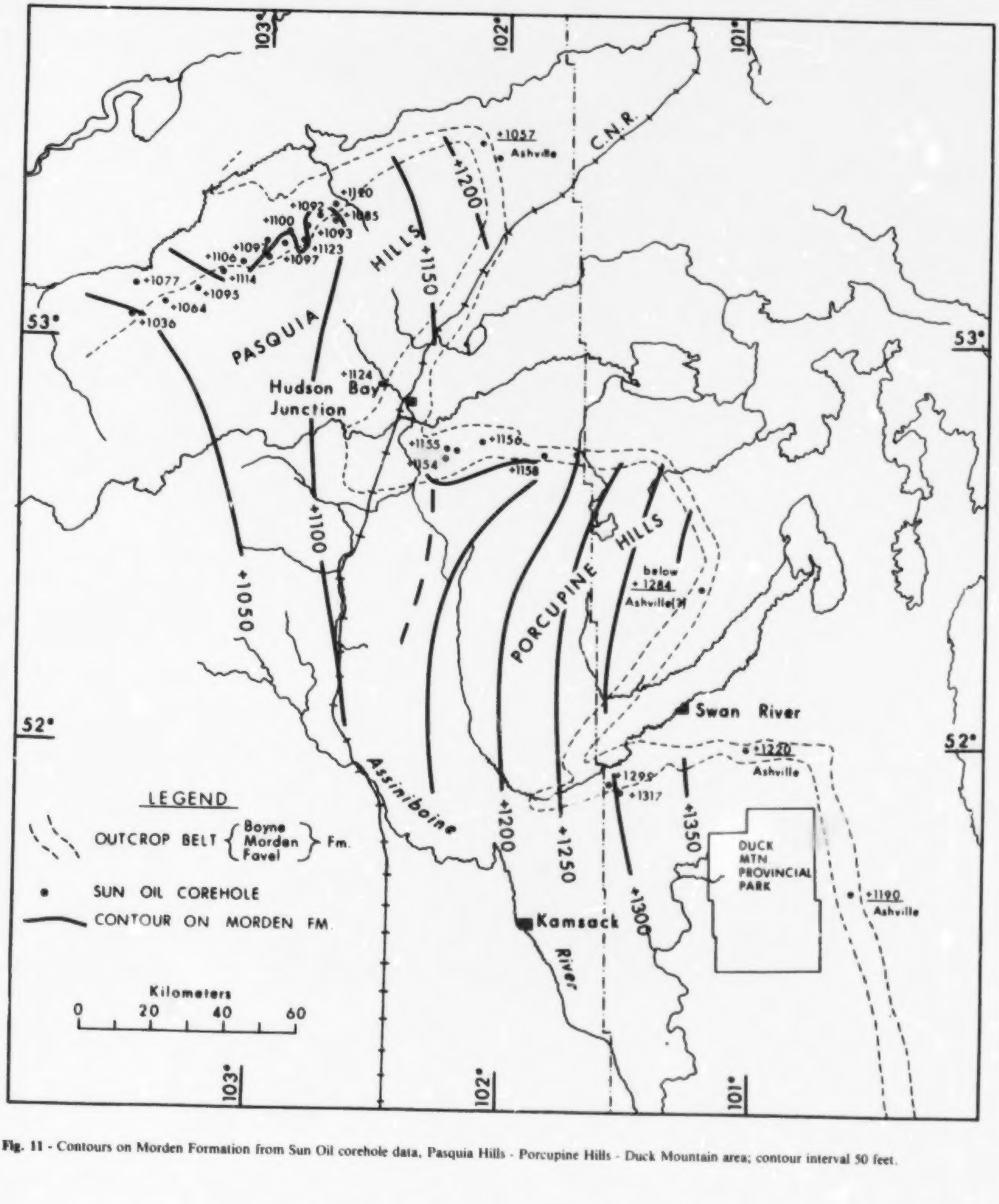
103°
102°
101°
53°
52°
C.N.R.
+1057
Ashville
+1110
+1092
+1085
+1100
+1093
+109
+1123
+1106
+1097
+1114
+1077
+1095
+1064
+1036
PASQUIA
HILLS
+1200
+1150
+1124
Hudson Bay
Junction
+1155
+1156
+1154
+1158
+1100
+1050
PORCUPINE
HILLS
below
+1284
Ashville(?)
Swan River
+1220
Ashville
+1299
+1317
Assiniboine
+1200
+1250
+1300
+1350
DUCK
MTN
PROVINCIAL
PARK
+1190
Ashville
Kamsack
River
LEGEND
OUTCROP BELT
Boyne
Morden
Favel
Fm.
SUN OIL COREHOLE
CONTOUR ON MORDEN FM.
Kilometers
0
20
40
60

Fig. 11 - Contours on Morden Formation from Sun Oil corehole data, Pasquia Hills - Porcupine Hills - Duck Mountain area; contour interval 50 feet.

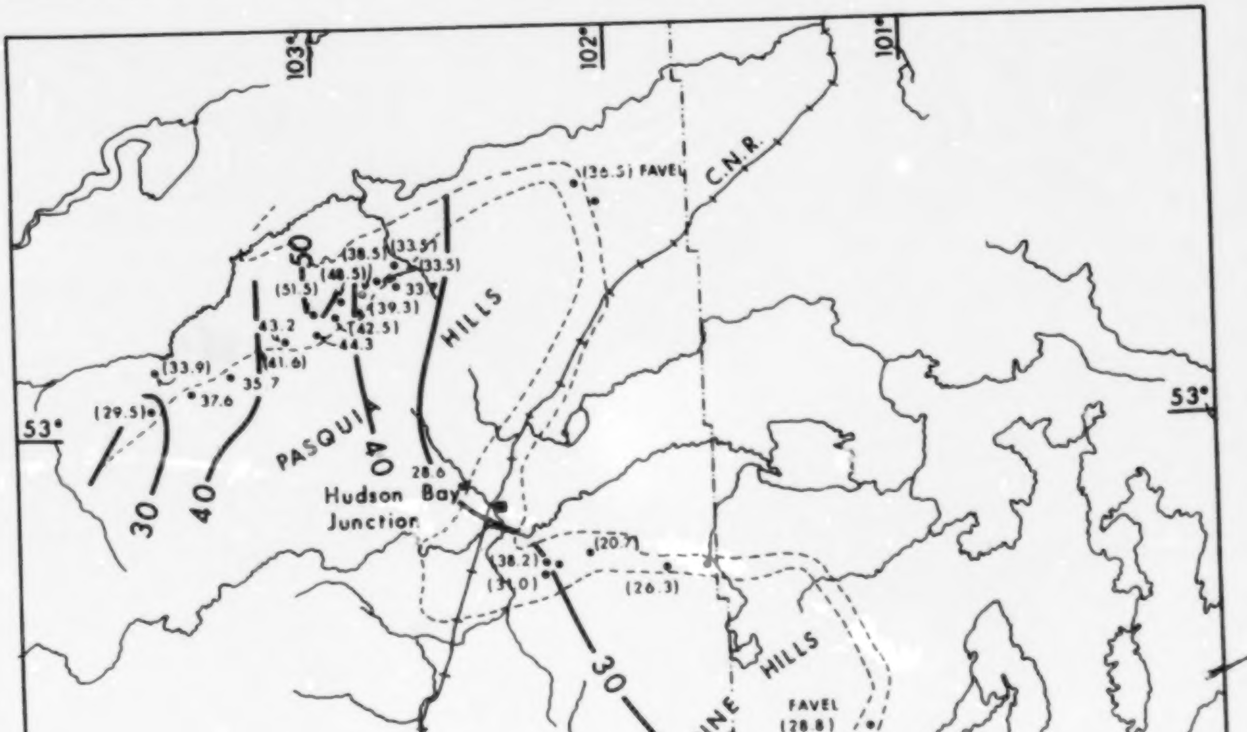
103°
102°
101°
53°
52°
C.N.R.
(36.5) FAVEL
(38.5)
(33.5)
(33.5)
(48.5)
(51.5)
33.7
(39.3)
(42.5)
43.2
44.3
(41.6)
(33.9)
35.7
37.6
(29.5)
50
40
30
PASQUIA HILLS
28.6
Hudson Bay Junction
(20.7)
(38.2)
(31.0)
(26.3)
PORCUPINE HILLS
FAVEL (28.8)
Swan River
(29.3) FAVEL
31.6
Assiniboine River
DUCK MTN PROVINCIAL PARK
(28.3) FAVEL
Kamsack
LEGEND
OUTCROP BELT Boyne Morden Favel Fm.
SUN OIL COREHOLE
37.6 (29.5) YIELD kg/t Complete Zone Incomplete Section
Isopachous Contour Of Average Hydrocarbon Yield – Boyne Fm
0 20 40 60
Kilometers

Fig. 12 - Average hydrocarbon yield from the Boyne Formation, from Sun Oil corehole data, Pasquia Hills - Porcuping Hills - Duck Mountain area.

The quality of oil recovered is in the poorer range of shale oil types, with specific gravities averaging 0.952 at the southerly end of the Manitoba Escarpement, and becoming heavier northward to 0.965 - 0.970 in the Porcupine and Pasquia Hills. Because Rock-Eval data are not available for comparison to the Fischer Assays in the northern area, no reason is readily evident for the northward increase of specific gravity.

Also of possible economic significance is the large amount of water indicated by the Fischer Assays. Almost all assays yielded a minimum 40 kg/t (10 US gallons/ton) with many ranging to 80 kg/t and some as high as 120 kg/t. These yields reflect the hydrated water of clay minerals, zeolites, sulfates and oxides.

SOURCE ROCK POTENTIAL

Thermal maturation, as interpreted from the values of T_{max} and of the hydrogen and oxygen indices, indicate that oil has not been generated from these two zones over almost the entire study area. Immaturity is verified by the production indices, the ratio of S_1 volatile oil content to the total hydrocarbon recovery ($S_1 + S_2$), which generally range from 0.02 to 0.06, occasionally up to 0.10, in the oil shale zones (Figs. 6a, b). Production index values of 0.25 to 0.31 at 6-33-11-28W4M, in southwestern Alberta, confirm marginal maturity and possible oil generation in that area.

At 6-34-30-8W4M, production indices average 0.31, ranging as high as 0.55. Other data, especially T_{max} (average 415 °C), indicate the kerogen to be thermally immature. The petroleum (S_1) content and in part the excellent hydrocarbon yield (Fig. 10b) result from contamination by an oilbase drilling fluid.

Dry gas is prevalent in the Milk River and Medicine Hat Formations of southeastern Alberta and southwestern Saskatchewan where sandstone units pinch out undip into the two White Specks (Boyne and Favel) units. An early biogenic origin from the kerogen of these deposits has been proposed for this gas (Fuex, 1977). Gas reported near Kamsack, Saskatchewan (Fig. 11) (Wickenden, 1945), although of limited economic significance, is of interest because of probable similar biogenic origin.

SUBHEAD

Potential oil shales of the Boyne and Favel Formations (First and Second White speckled shales) are thermally immature across the Prairie Provinces, except for possible low maturity in western Alberta. Type III humic material provides some organic carbon content everywhere, with additional Type II sapropel increasing the organic carbon along two north-south trends, one in western and one in eastern Saskatchewan. These areas of maximum organic content are developed as cross trends to a regional northeasterly increase of kerogen content. Yields per 1% organic carbon increase as the Type II content increase, from lows of 3 to 3.5 to highs of 6 to 6.5 kg/t/1% organic carbon. The best yields average better than 40 kg/t for both zones along the north slope of the Pasquia Hills in eastern Saskatchewan and toward the outcrop at the west of the province, although control data are sparse in the latter area.

Kerogen content increases to an average maximum where calcite approximates 40% in the Boyne and 60% in the Favel and decreases significantly in relatively pure limestone beds. Calcite concentrations are inversely proportional to the quartz-clay-feldspar component.

Secondary mineral suites, including zeolites, sulfates, oxides, and considerable iron minerals, all containing varying amounts of water of crystallization, indicate continuing mineral alteration during deposition and lithification. These may be economically significant by contribution of water yield additional to that of the clays: excess water can be a problem for retorting processes. The contribution of these minerals to rock incompetency may also be an impediment to a mining process.

Except for western Alberta, these zones have not been the source of any hydrocarbons resulting from thermal maturation, but have probably contributed significantly to eastern Alberta and western Saskatchewan gas reserves by early biogenic degradation processes.

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L. R. Snowdon, F. D. Ball and D. F. Paterson read the original open-file, contributing significantly through their comments. This paper has been reviewed by J.E. Christopher, whose editorial comments have significantly increased the quality of presentation.

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THE CoRes LOG, A CORE—RESISTIVITY LOG EVALUATION FOR ENHANCED FORMATION EVALUATION

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ABSTRACT

Core analysis data have historically played a fundamental and important role in formation evaluation. Measured porosity and permeability data identify storage capacity and productive potential and measured fluid saturations identify the presence, magnitude and distribution of core residual hydrocarbons and water. However, interpretive criteria are required to evaluate these saturation data in order to predict the type of production expected.

The interpretation of core analysis is often perplexing and in many cases inconclusive as marginally economic prospects and problematic conditions prevail. These situations necessitate the extension of core analysis interpretation methods and the integration of these data with downhole resistivity log response.

Core analysis data provide the basis for an interpretive method that is independent of core residual saturations and combines both core and downhole log data. The method is referred to as the Core-Resistivity Evaluation (CoRes). The approach integrates core analysis, special core analysis, and reservoir fluid data and it exploits the synergistic relationship between core analysis and downhole log derived data. The CoRes concept is based on the premise that measured core permeability and porosity are related to pore geometry characteristics which control critical upper limits of formation water saturation that must not be exceeded for a specified water cut.

The core derived critical water saturation can be directly compared to formation water saturation calculated from downhole log response. Alternatively, the core derived critical water saturation can be converted to its equivalent resistivity, and superimposed on the downhole log curves.

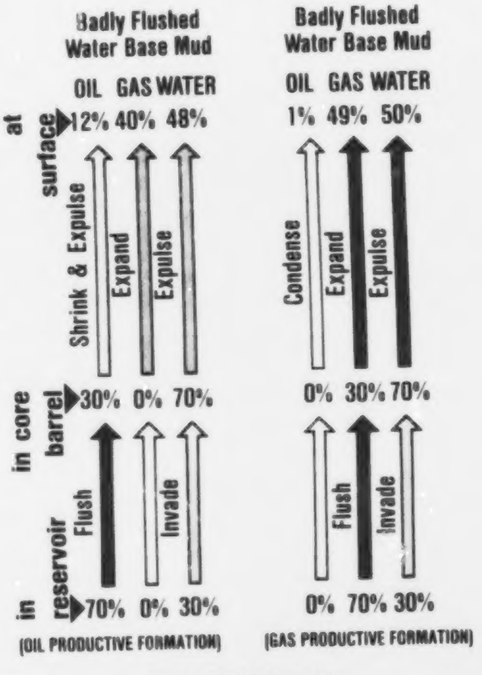
Critical water saturation values have been developed for formations encountered in Canada. The CoRes evaluation has been implemented as a formation evaluation and well completion aid. Selected examples are presented.

INTRODUCTION

Conventional core analysis data provide fundamental insight into reservoir petrophysics. The magnitude, distribution and inter-relationship of permeability, porosity, and matrix density in conjunction with a visual assessment of lithology provide an opportunity to evaluate reservoir textural characteristics and pore geometry. Core fluid saturations identify the presence and distribution of hydrocarbons, and their relative magnitudes identify potentially productive horizons, transition zones and fluid interfaces.

Interpretation of conventional core analysis requires an integration of rock characteristics and core fluid saturations. Although insitu saturations are altered by coring fluid filtrate invasion and pressure depletion, core analysis interpretation experience provides insight into the most probable type of fluid production.

Saturations observed in the laboratory are dependent upon a complex inter-relationship of many variables including the coring fluid type, the relative degree of filtrate invasion, pressure depletion, pore geometry, the quantity and distribution of insitu fluids, the viscosity ratio of displacing/displaced fluids, relative permeability characteristics, capillary properties, structural position, and others. Figure 1 illustrates typical saturation changes for oil and gas productive reservoirs cored with water base coring fluid. The surface condition saturation data can be correlated with production data and utilized qualitatively for interpretation. Table 1 illustrates the type of production normally associated with core analysis residual hydrocarbon and water saturations for several Canadian formations.



Typical Fluid Contents
From Reservoir To Surface

FIGURE 1

TABLE I

FORMATION: GLAUCONITIC

TYPE OF PRODUCTION	S_{OR} (FRACTION PORE SPACE)	S_{TW} (FRACTION PORE SPACE)
Oil	≥ .125	≤ .45
Gas	≤ .05	≤ .45
Water	≤ .125	≥ .45

FORMATION: CUMMINGS

TYPE OF PRODUCTION	S_{OR} (FRACTION PORE SPACE)	S_{TW} (FRACTION PORE SPACE)
Oil	≥ .38	≤ .38
Gas		
Water	≤ .38	≥ .38

FORMATION: VIKING

TYPE OF PRODUCTION	S_{OR} (FRACTION PORE SPACE)	S_{TW} (FRACTION PORE SPACE)
Oil	≥ .08	≤ .42
Gas	≤ .020	≤ .42
Water	≤ .08	≥ .42

In many cases stand-alone interpretation of conventional core analysis data is sufficent for successful formation evaluation. An ideal example of an oil productive glauconitic interval that illustrates the inter-relationship of rock properties and core saturations and the application of the data for interpretation is found in Figure 2. Rock property and residual saturation data indicate oil production where the rock is permeable. The zone was completed from 952.0 to 957.5 metres and produced 18 metres (Osborn and Hogan, 1972) of water free oil per day.

The interpretation of core data is not always straightforward. The data can indicate reservoir quality with expected hydrocarbon production based on saturation criteria; however, wells may produce with significant water cut and ultimately prove to be non-commerical. An example of these saturation conditions is illustrated in Figure 3. Using the core saturation interpretation criteria in Table 1, the zone would be interpreted as oil productive. The low permeability indicates a potential requirement for stimulation. In this well, however, the zone was completed from 996 to 1004 metres and produced 50% water cut.

In the latter case, interpretation of conventional core analysis saturations is difficult and may result in invalid conclusions. In this and similar cases, interpretation methods must be extended to incorporate all available rock property information as well as the downhole log response. (Granberry and Wilshusen, 1962; Osborn, 1975; Osborn and Hogan, 1972).

Logs in low permeability rock often yield high calculated water saturations, resulting in condemnation of prospects that will yield oil and gas. Consequently, the log derived data, just as the core analysis, may yield invalid conclusions as to well productivity. A combination of conventional core analysis permeability and porosity which has been extended and integrated with specialized core data yields critical upperlimits of formation water saturation for water-free production. These critical saturations, when combined with downhole log response enhance formation evalutaion.

CORRELATION OF ROCK AND FLUID PROPERTY DATA

Critical interstitial water saturation (S_{ciw}) is controlled by pore configuration, capillary pressure characteristics, wettability, relative permeability relationships, and viscosity-dependent fractional flow characteristics (Granberry and Keelan, 1977). Critical interstitial water saturations for specific rock/fluids systems can be established by physical measurement of controlling variables in the laboratory and inter-relating these data.

Core samples for specialized tests are selected to characterize pore geometry. Typically, a suite of samples is selected on the basis of visual core examination and a permeability vs. porosity relationship within a specific lithological unit. In complex lithologies sample selection is enhanced by detailed petrology studies that define depositional sequences, identify subtle textural changes and pore structure and provide for definitive rock typing.

After sample selection and screening criteria are established, capillary pressure and relative permeability characteristics are determined to quantify water saturation distribution and to predict performance characteristics. Formation resistivity factor (FRF) vs. porosity at simulated net overburden pressure and resistivity index (I) vs. water saturation (S_w) relationships are established to determine the cementation exponent (m) and the saturation exponent (n) needed to refine resistivity computation from core data.

Water cut vs. water saturation or water-gas ratio vs. water saturation relationships (application dependent) are calculated using appropriate relative permeability data, formation volume factor and viscosity ratios. At this point an arbitrary water cut (or water-gas ratio) limit can be established. Corresponding water saturations, termed critical interstitial water saturations (S_{ciw}), can be read from the individual water cut curves. Critical water saturations can then be correlated with core permeability and porosity. Figure 4 illustrates the data required to establish S_{ciw} values and to refine resistivity calculations. Figure 4 also illustrates the inter-relationship of core analysis and special core analysis data.

Once established, the core derived critical water saturation data can be compared directly to formation water saturations derived from log response.

The advantage of this technique is that the critical saturations, which are function of pore configuration and fluid properties, can be applied independently of core fluid saturations and compared to actual formation saturations. If the formation water saturation exceeds the critical interstitial water saturation the reservoir will produce with significant water cut and the converse is true if the formation water saturation is less than the critical interstitial water saturation.

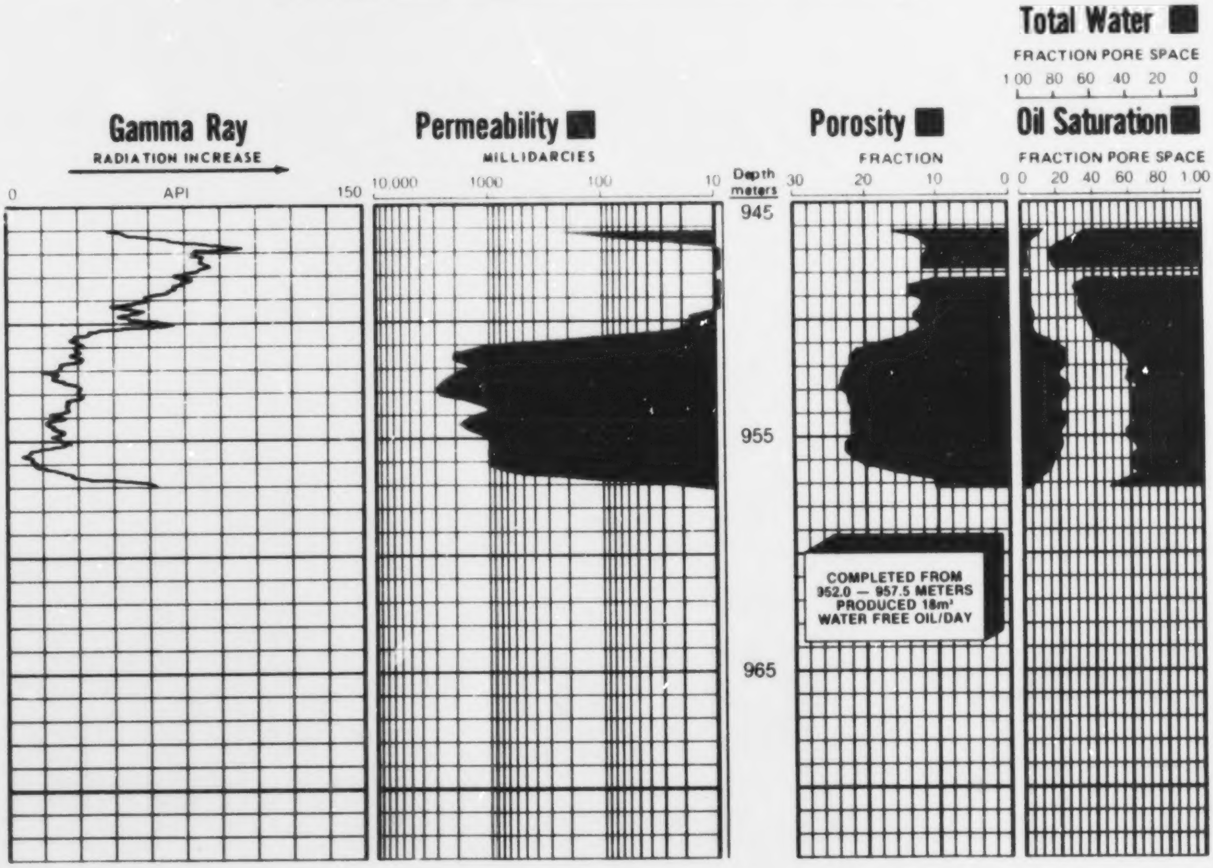
THE CoRes LOG

Comparison of critical interstitial water saturation to formation water saturation is somewhat time-consuming in that the log water saturations must be computed as a function of depth before comparisons are made. For ease of interpretive application resistivities corresponding to critical water saturation can

CORE LABORATORIES – CANADA, LTD. CORE LAB *Petroleum Reservoir Engineering*

COMPANY ______ FILE NO. ______
WELL ______ DATE ______
FIELD ______ FORMATION GLAUCONITIC ELEV. ______
PROVINCE ______ DRLG. FLD. WATER BASE MUD CORES 1, 2
LOCATION ______

CORRELATION COREGRAPH



COMPLETED FROM 952.0 — 957.5 METERS PRODUCED 18m³ WATER FREE OIL/DAY

FIGURE 2

CORE LABORATORIES – CANADA, LTD. CORE LAB *Petroleum Reservoir Engineering*

COMPANY GRIFCO EXPLORATION, LTD.
WELL GRIFCO GRIEVANCE 10-10-10-10 FILE NO.
FIELD GRIEVANCE FORMATION GLAUCONITIC DATE
PROVINCE DRLG. FLD. WATER BASE MUD ELEV.
LOCATION LSD 10-10-10-10 W10M CORES 1, 2

CORRELATION COREGRAPH

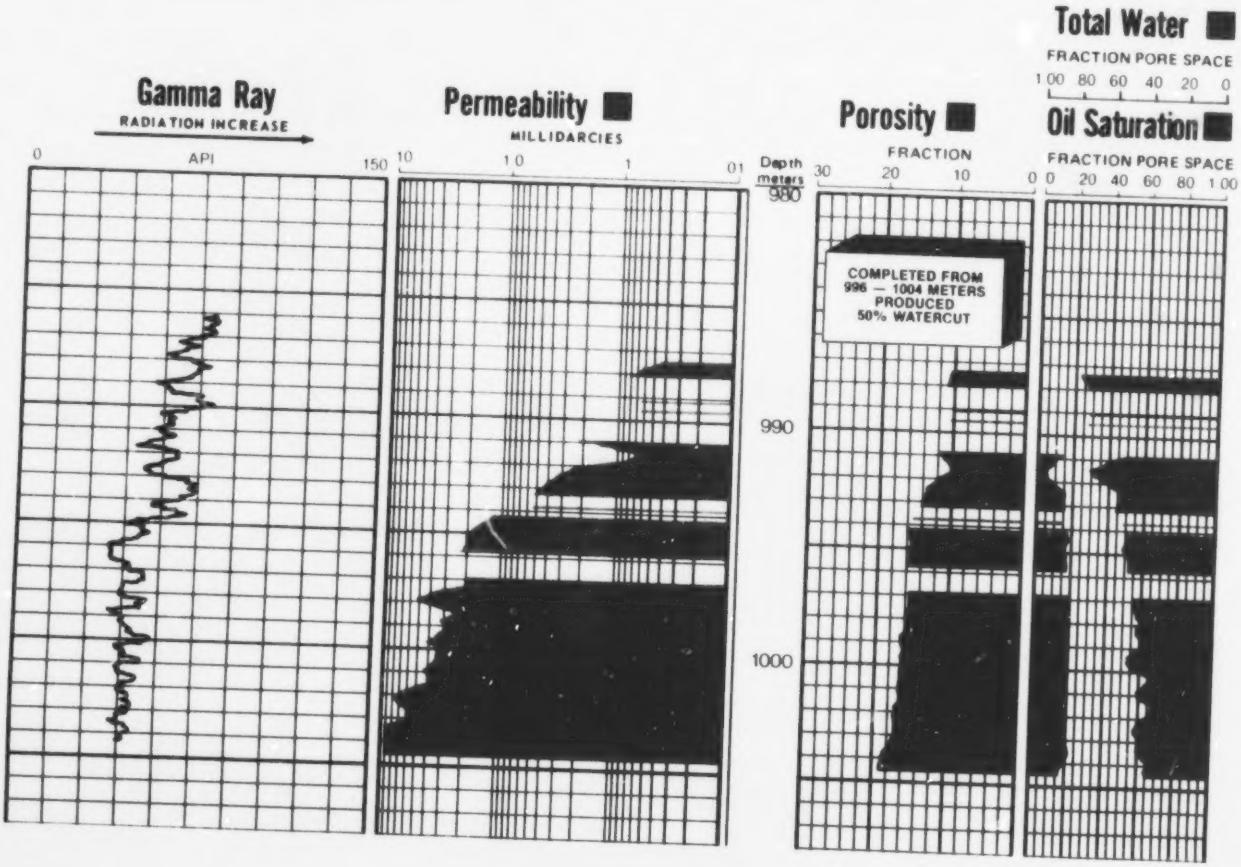
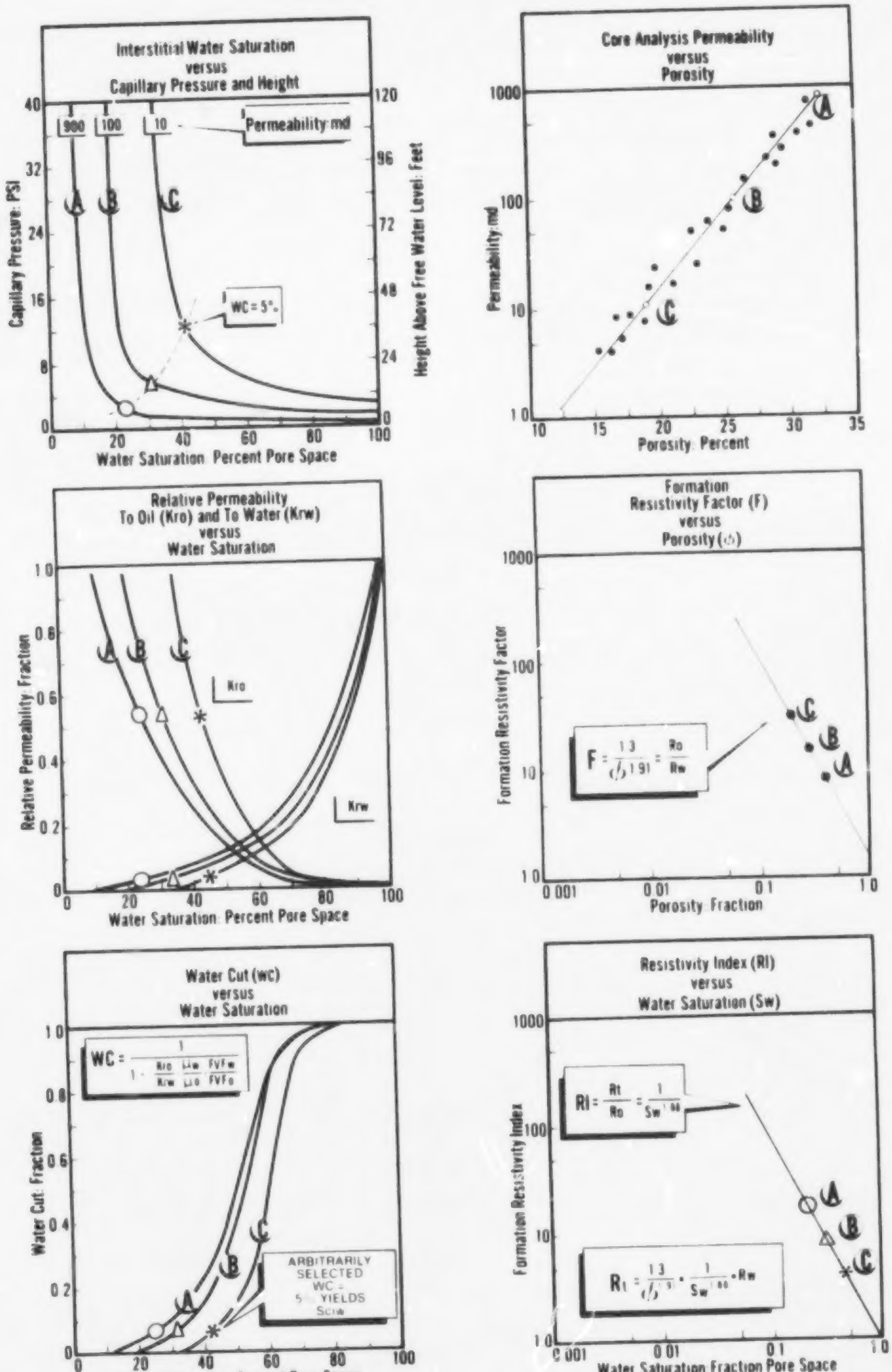


FIGURE 3



Reference: SPE 4160
Keelan, Dare. "Core Analysis Techniques and Application", Paper Presented at Columbus, Ohio SPE Meeting (Nov. 8-9, 1972)

Relationship Of Core Analysis and Special Core Analysis Data

FIGURE 4

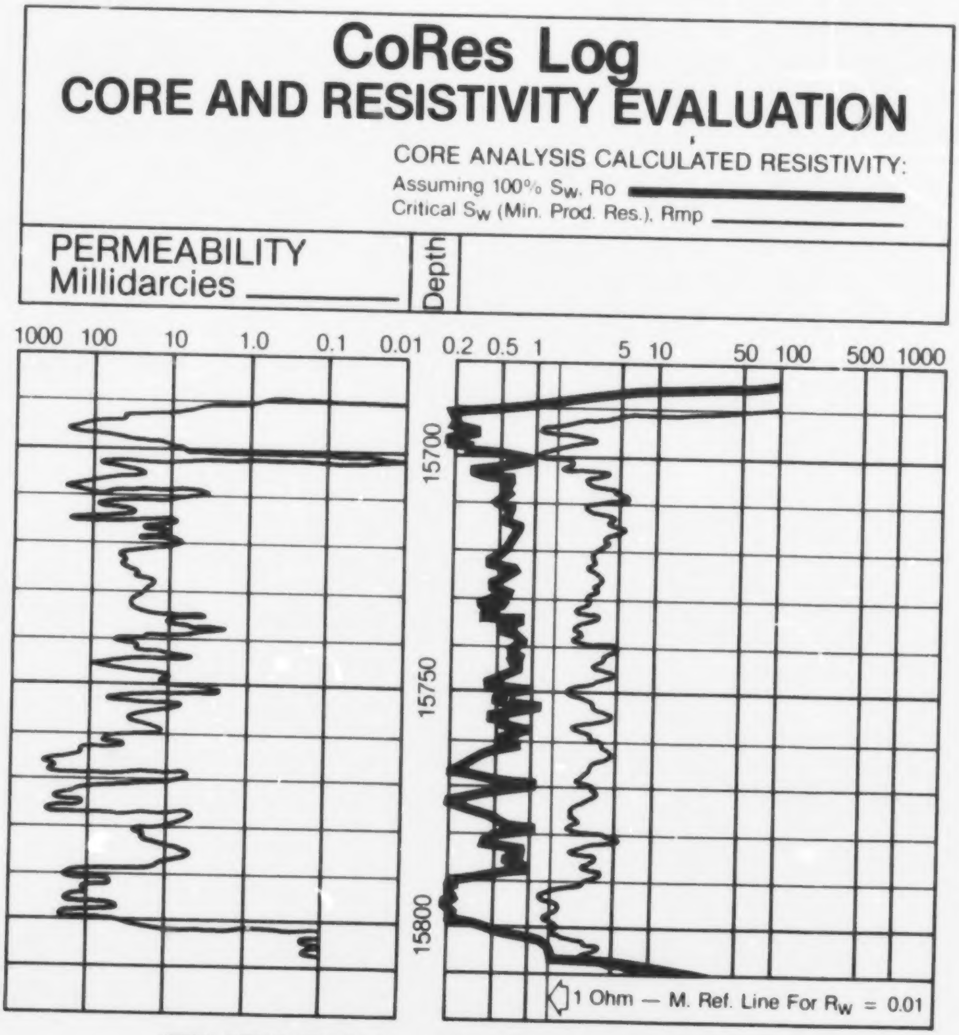
be computed from core data and plotted in resistivity log compatible format. This approach yields a log compatible overlay for quick-look, high confidence decision making.

Typical CoRes Log (Granberry and Tucker, 1973) format is illustrated in Figure 5. The log is comprised of a core permeability curve and two core resistivity curves. A resistivity profile at 100% water saturation (R_o) is calculated from core porosity using Equation 1. A minimum productive resistivity curve (R_{mp}) is calculated by substituting the critical water saturation (S_{ciw}) for S_w in the Archie equation and solving for the resistivity variable as illustrated in Equation 2. The R_{mp} curve is a resistivity profile at S_{ciw} and identifies the resistivity magnitude required to produce hydrocarbons without significant water.

$$R_o = F \times R_w \quad \text{Where } F = \frac{a}{\phi^m} \qquad (1)$$

$$R_{mp} = \frac{F \times R_w}{S_{ciw}{}^n} \quad \text{Where } F = \frac{a}{\phi^m} \qquad (2)$$

The CoRes Log is used to interpret type of expected production via R_{mp} - R_t comparison. The CoRes Log can also be used to evaluate the impact of porosity change on R_t by monitoring R_o which is inversely related to porosity. The R_{mp} reflects changes in both porosity and permeability. In zones of essentially equal porosity a change in R_{mp} mirrors changes in formation permeability. The lower the permeability, the higher the critical water, and the lower the minimum productive resistivity.



TYPICAL CoRes LOG

FIGURE 5

TYPICAL EXAMPLE CASES

A suite of sandstone and carbonate examples to illustrate the practical application of the CoRes Log as an exploration tool follow:

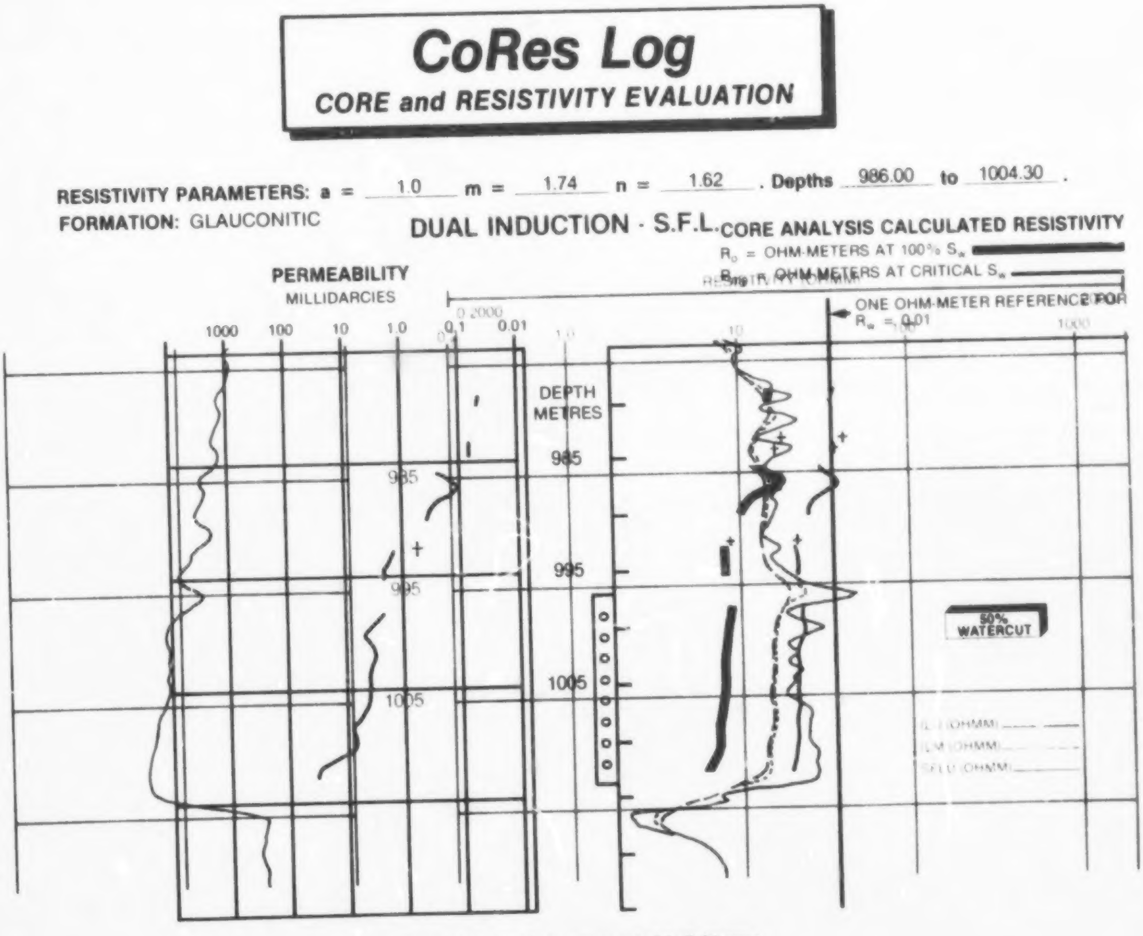
Example 1

The first example is illustrated in Figure 6. The data presented consists of a dual-induction spherically focused log (DISFL) which includes a spontaneous potential log (SP) and the CoRes Log overlay of the Glauconitic Formation. In this and subsequent examples the downhole log data is represented in light grey. The CoRes Log overlay is superimposed and represented in dark grey and black. The conventional core analysis data for this example is illustrated in Figure 3. Core resistivity properties evaluated in the laboratory were used to compute the core resistivity curves. Measured values are a = 1.0, m = 1.74 and n = 1.62 as identified in Figure 6.

A core-to-log depth discrepancy of 0.5 metres was observed by comparing the core permeability curve to the SP. This was confirmed by core gamma-to-insitu gamma comparison (not illustrated). The depth discrepancy was resolved by shifting the CoRes Log overlay vertically.

The core resistivity cure R_o and R_{mp} were calculated with an arbitrary formation water resistivity (R_w) = .01 ohm-metres, as the R_w is typically unknown at the time of CoRes preparation. Correction to the actual R_w is achieved by shifting the CoRes Log horizontally. The CoRes Log one ohm-metre reference line must be placed over the log resistivity value which equals the actual R_w multiplied by 100. In this example, R_w equaled 0.346. The CoRes one ohm-metre reference line is placed over the log 34.6 ohm-metre resistivity line.

The core R_{mp} profile is greater than the deep induction curve (ILD), which indicates that reservoir water saturation exceeds the critical water saturation throughout the entire interval. This condition indicates that the zone cannot be successfully completed without water cut. The relative position of the ILD profile between the core R_{mp} and R_o curves indicates 45 to 50% water cut. The zone was completed from 996 to 1004 metres and produced 50% water cut.



Down Hole Log Data represented in light grey.
CoRes Log Overlay represented in dark grey and black.

FIGURE 6

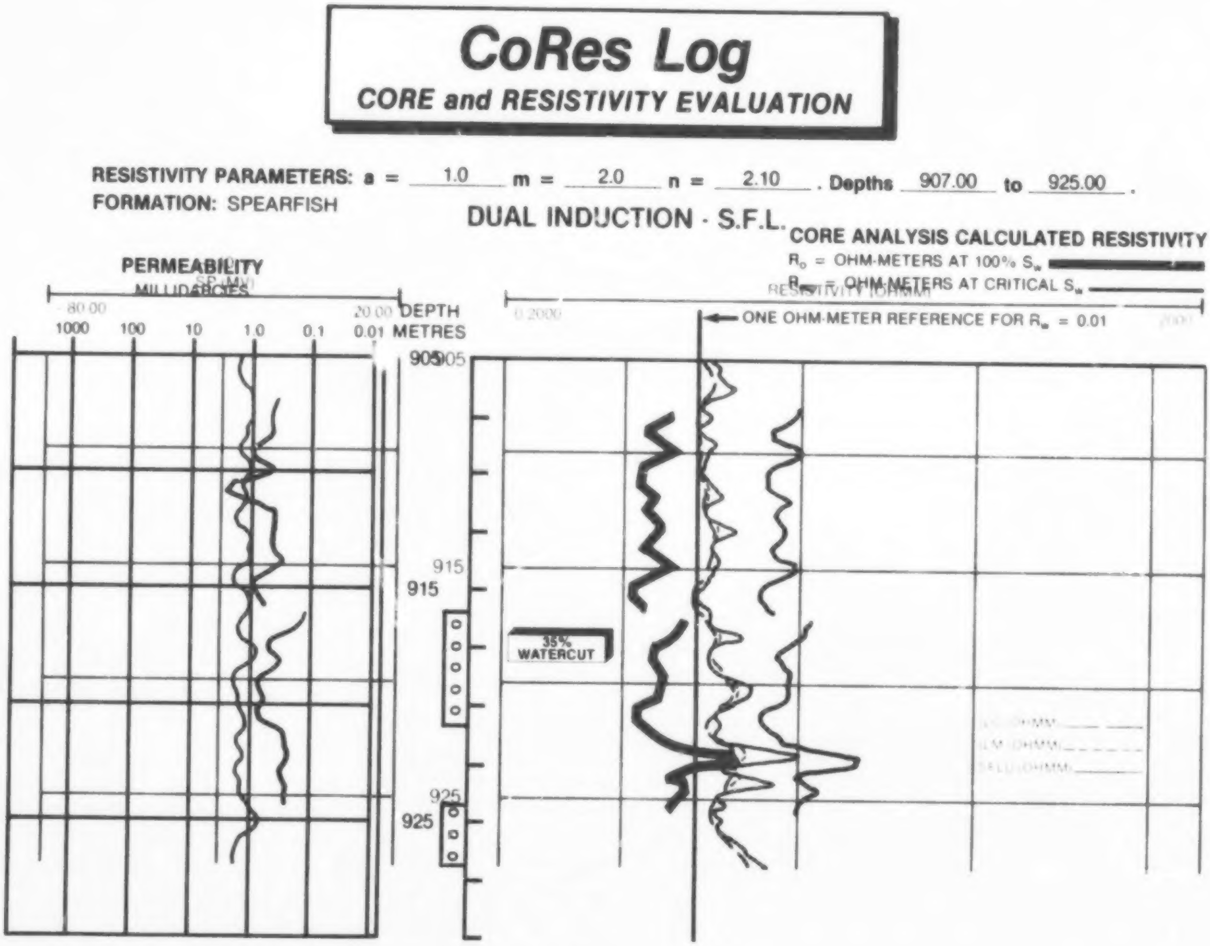
Example 2

The second example is illustrated in Figure 7. The data presented consists of the DISFL with SP and the CoRes Log overlay of the Spearfish Formation.

A core-to-log depth discrepancy of 1.0 metre was resolved as in the previous example and the one ohm-metre reference line was shifted horizontally to compensate for R_w = .028 ohm-metres.

The core R_{mp} profile greater than ILD indicates that S_w exceeds S_{ciw} throughout the interval. As in the last example, this condition indicates water production. The CoRes Log predicts 45 to 50% water cut as compared to an actual water cut of 35% through completions at 915 to 921 metres and 924 to 927 metres.

The discrepancy between predicted and actual water cut is thought to be related to assumed values assigned to a, m and n to prepare the preliminary log. Physical measurements of a, m and n are currently in progress to refine CoRes Log computation.



Down Hole Log Data represented in light grey.
CoRes Log Overlay represented in dark grey and black.

FIGURE 7

Example 3

Example 3 is illustrated in Figure 8 and consists of a DISFL with SP and the CoRes Log overlay of the Viking Formation.

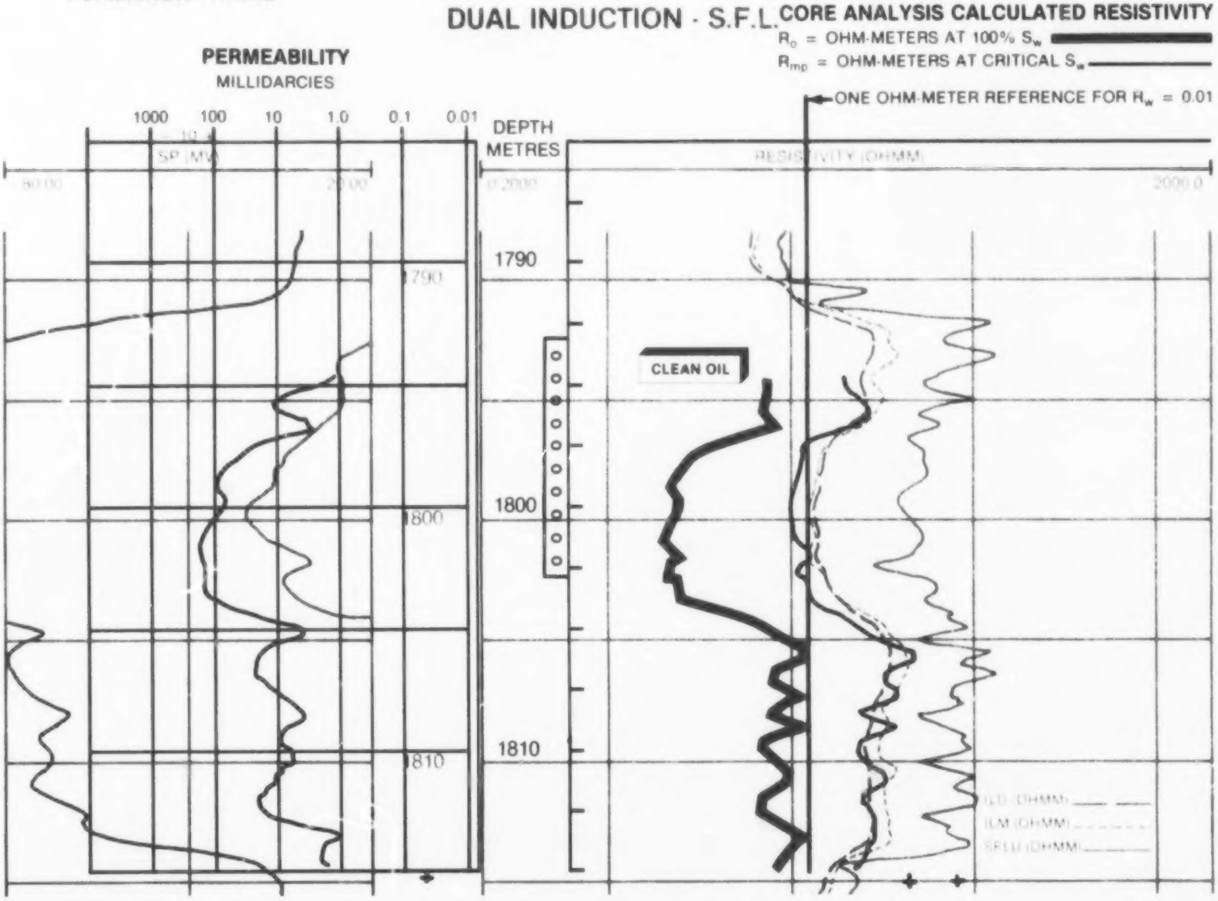
A core-to-log depth discrepancy of 0.5 metres was resolved and the CoRes shift was made to compensate for R_w = .12 ohm-metres. Values of a = 1.0, m = 1.81 and n = 2.58 were determined from core physical measurements and used to compute the R_o and R_{mp} curves.

The ILD profile marginally exceeds the R_{mp} profile from 1796 to 1805 metres and is marginally less than the R_{mp} profile below 1805 metres. The condition of R_{mp} less the ILD indicates insignificant water cut from 1796 to 1805 metres and ILD less than R_{mp} below 1805 metre indicates nominal water cut by relative comparison of curves. The interval was completed from 1793 to 1803 metres and produced water free oil.

CoRes Log
CORE and RESISTIVITY EVALUATION

RESISTIVITY PARAMETERS: a = 1.0 m = 1.81 n = 2.58 . Depths 1795.00 to 1825.45 .

FORMATION: VIKING



Down Hole Log Data represented in light grey.
CoRes Log Overlay represented in dark grey and black.

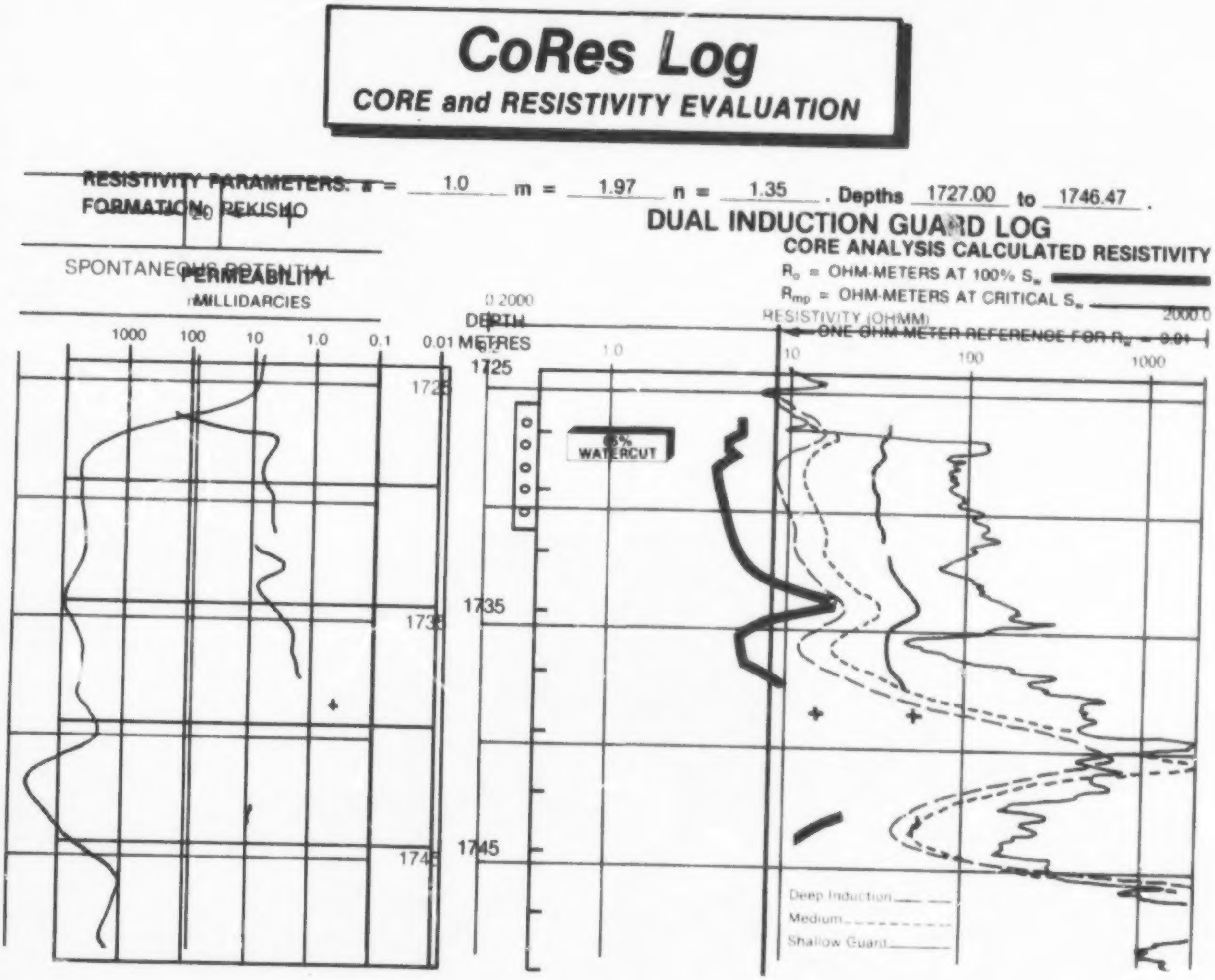
FIGURE 8

Example 4

The fourth example is illustrated in Figure 9. The data presented consists of a dual-induction guard log with SP an the CoRes Log overlay of the Pekisko Formation. Values of a = 1.0, m = 1.97 and n = 1.35 were determined in the laboratory and were used to compute R_o and R_{mp} curves.

The core-to-log depth discrepancy of approximately 0.5 metres was resolved and the one ohm-metre reference line was shifted horizontally to compensate for R_w = .08 ohm-metres.

The core R_{mp} profile greater the ILD indicates that S_w exceeds S_{ciw} throughout the entire interval. The relative position of the ILD profile between the core resistivity curves generally predicts 60 to 70% water cut for the interval. The Pekisko zone was completed from 1726.5 to 1732 metres and produced 65% water cut.



Down Hole Log Data represented in light grey.
CoRes Log Overlay represented in dark grey and black.

FIGURE 9

CONCLUSIONS

Formation evaluation is enhanced by integrating all available complementary data. The CoRes Log can be applied successfully to integrate valuable reservoir data including core analysis, specialized core analysis and fluid properties in a practical manner. These data can be further utilized to independently evaluate resistivity log response.

The following conclusions are presented:

1. Correlation of conventional core analysis data and critical water saturation can be achieved.
2. Interpretive reliability can be increased by comparison of S_w and S_{ciw} to evaluate productive possibilities.
3. Core derived R_{mp} and R_o profiles in log compatible format enhance the application of the critical water saturation concept.

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LOG CORRELATION STUDIES IN SASKATCHEWAN

PETROLEUM GEOLOGY SECTION
Saskatchewan Geological Survey
Saskatchewan Energy & Mines

The Petroleum Geology Section has begun a programme with the object of producing geophysical log cross-sections of the Phanerozoic strata in Saskatchewan. They will be used in-house for on-going log-picking and stratigraphic correlation studies and will also be available in blue-line form to the public.

Two series are being constructed: (1) Regional Sections which will employ wells more than ten kilometres apart and tie into the East-West and North-South sections of Hutt (1963). These will eventually form a grid covering all of the sedimentary section of Saskatchewan. (2) Local Sections which will employ wells less than ten kilometres apart and which will be restricted to the petroleum-producing areas. Both series will be reproduced with a vertical scale of 1 cm: 12 m (1 in: 100 ft).

Stratigraphcially, each section will encompass one of four divisions within the Phanerozoic. These are Mesozoic, Mississippian, Devonian, and Lower Palaeozoic, designated MZ, MISS, DEV, and LP respectively. Sections will also be designated "W" if in the area west of the third meridian (Longitude 106°) and "E" if to the east of it and will also contain a year and number code as in the following example:

Local Section MZ-W-84-1

This indicates the first cross-section in 1984 west of the third meridian, such cross-section being of the Mesozoic strata with adjacent wells closer than 10 km.

The published sheets will also contain name(s) of author(s), date compiled and/or updated, and other information deemed relevant. This might be a typical log in the case of local sections or thickness variation data in the case of regional sections.

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ADDENDUM

OIL AND GAS IN SASKATCHEWAN

Proceedings of a Symposium
Held in Regina, Saskatchewan
11 & 12 October 1984

EDITORS:
J. A. LORSONG and M. A. WILSON

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S4P 2Z6 CANADA

DEPOSITIONAL MODELS FOR THE DUPEROW AND BIRDBEAR FORMATIONS: IMPLICATIONS FOR CORRELATION AND EXPLORATION

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15702 West Hardy Road
Houston, Texas 77060

ABSTRACT

Carbonates and evaporites of the Upper Devonian Duperow and Birdbear (Nisku) Formations were deposited upon an immensely broad cratonic shelf that extended more than 1300 km (800 mi) southeastward from the Duvernay-Ireton basin in central Alberta, across Saskatchewan, Montana and North Dakota into Wyoming and South Dakota (Fig. 1). Perhaps the most striking feature displayed by these formations is the remarkable lateral persistence of individual strata, allowing for shelf-wide stratigraphic subdivision and correlation. This summary presents models for the deposition of the Duperow and Birdbear Formations, and includes general remarks regarding the significance of a combined stratigraphic/facies approach in exploration for hydrocarbon reservoirs.

Previous investigators have emphasized the cyclical carbonate-evaporite deposition of these formations (Andrichuk, 1951). They have uniformly presented shoaling-upward sedimentary cycles which are terminated by intertidal and supratidal sabkha deposition, resulting from repeated marine flooding followed by total evaporation of the periodically barred lagoonal shelf. There is general agreement that the Birdbear Formation represents a single sedimentary cycle (Sandberg and Hammond, 1958; Nichols 1970; Halabura, 1982), but there is little concensus on the number of Duperow cycles. According to Wilson (1967), the Duperow Formation in Montana and North Dakota consists of 12 sedimentary cycles, each capped by sabkha evaporites and by mudstone characterized by wind-blown quartz silt and clay. Dunn (1975) established 26 cycles for the Duperow Formation in southern Saskatchewan, each terminating in sabkha evaporites and an emergent shelf subjected to widespread fresh-water sheet flooding that contributed fine clastic sediment. Hoganson (1978) recorded nine sedimentary cycles for the Duperow Formation in North Dakota; Altschuld and Kerr (1982) recorded five major cycles. According to both of the latter studies, intertidal and supratidal conditions dominated much of Duperow deposition.

In contrast, detailed study of cores and thin sections from 125 wells in Montana and North Dakota (an aggregate of over 12,000 ft) indicates that widespread development of supratidal conditions rarely occurred during deposition of this sequence. Instead, the development of the numerous sedimentary cycles which gave rise to laterally persistent marker beds was dominantly controlled by episodic changes in salinity virtually independent of water depth, and to a lesser degree by cyclic changes in bathymetry of either regional or local magnitude. These two phenomena operated independently to produce two distinct sets of vertical facies sequences.

Changes in bathymetry, recorded by asymmetric cycles of rapid transgression and prolonged regression are represented by three successive shoaling-upward sequences of carbonate facies which display broad areal continuity. The typical bathymetric cycle is modeled in Figure 2. The basal facies of these cycles consist of nodular-bedded, burrowed mudstone and wackestone containing sparse brachiopods and echinoderms (crinoids and echinoiderms) deposited in moderately deep water of normal marine salinity. Lesser constituents include peloids, intraclasts, calcispheres, codiacean algae, foraminfera, ostracods, gastropods, solitary rugose corals and the delicate tabulate coral *Aulopora*. This facies is succeeded by or alternates with stromatoporoid-coral banks and biostromes deposited in moderately deep to shallow water of normal marine salinity. Banks and biostromes are represented by three distinct subfacies. In order of decreasing water depth these are: 1) stromatoporoid-coral floatstone containing a diverse assemblage of branching and massive stromatoporoids and tabulate and rugose corals, but dominated by globular and domal stromatoporoids; 2) stromatoporoid boundstone and rudstone composed of abundant, largely *in situ* stromatoporoids of all forms in the Duperow Formation, but only by laminar and tabular stromatoporoids in the Birdbear Formation; and 3) *Amphipora* wackestone and packstone (cross bedded in places), also containing numerous laminar stromatoporoids.

Banks and biostromes are succeeded by an assemblage of shallow, restricted to hypersaline lagoon, intertidal and (rarely) supratidal facies, including peloid-intraclast and abraded-skeletal packstone, *Renalcis* algae-serpulid boundstone, laminated and stromatolitic mudstone, nodular-mosaic andydrite and reddish gray, hematitic, argillaceous mudstone (Fig. 2). These facies are futher characterized by ostracodes, calcispheres, mud cracks, breccia zones, fenestrae, and scour surfaces. Only two of the three bathymetric cycles exhibit complete regression. Widespread supratidal (sabkha) conditions are indicated for the top of the Duperow (the lower "Ireton kick") and for strata immediately above the Birdbear (the basal Three Forks Formation).

Episodic restriction of marine waters during Duperow deposition and at the culmination of Birdbear deposition, possibly triggered by small eustatic fluctuations of sea level, are documented by numerous thin, though distinctive, lithologic sequences which randomly punctuate the bathymetric cycles and record the gradual onset of hypersalinity. The vertical facies sequence of a typical salinity cycle is modeled in Figure 3. From the base upward, the sequence consists of: 1) peloid-intraclast packstone interbedded with laminated mudstone, containing sparse ostrcodes and calcispheres; 2) laminated or burrowed mudstone, but with burrowing decreasing upward; 3) stromatolitic mudstone; 4) massive, laminated to deformed anhydrite; and 5) greenish gray, pyritic, shaly, finely laminated mudstone exhibiting appreciable soft-sediment deformation. These compressed cycles apparently represent gradual increase in salinity to gypsum

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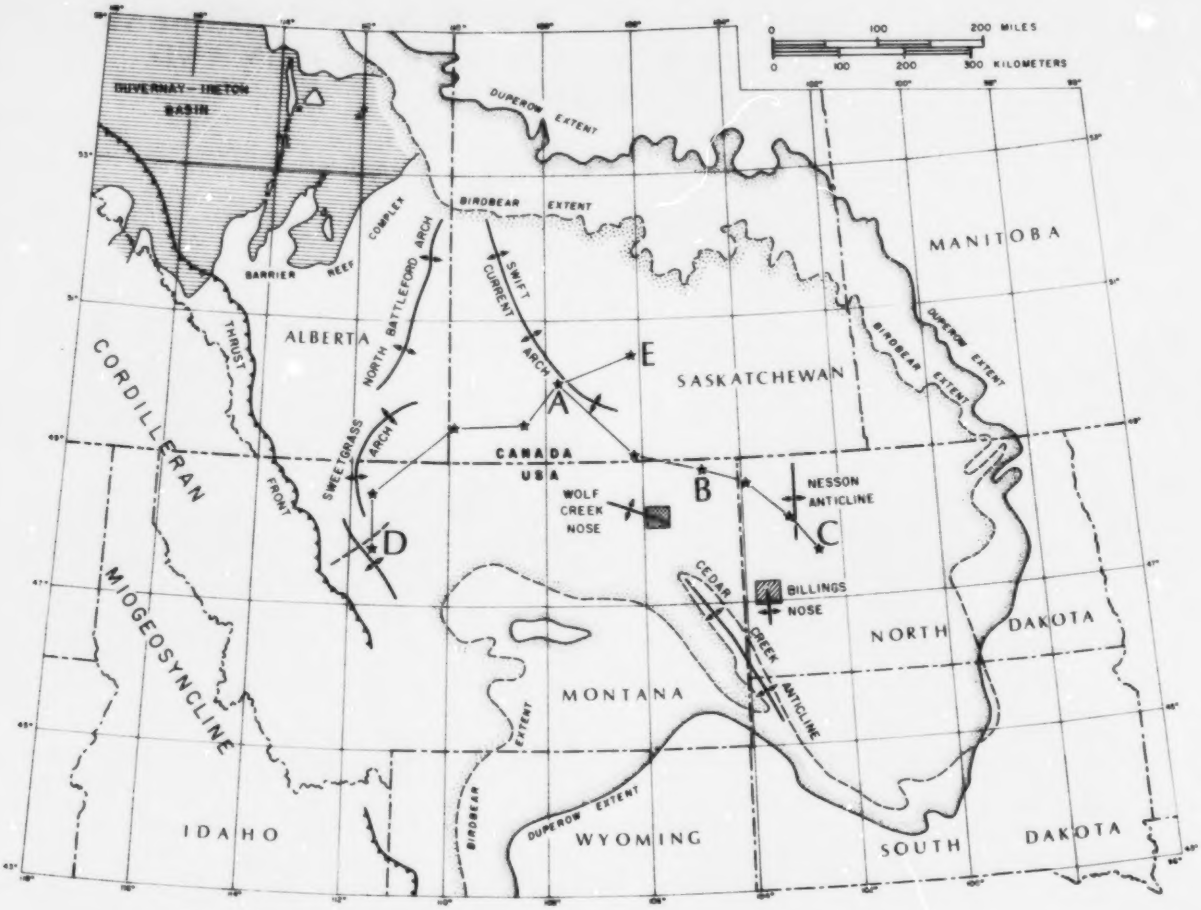
0 100 200 MILES
0 100 200 300 KILOMETERS
DUVERNAY–IRETON BASIN
BARRIER REEF COMPLEX
NORTH BATTLEFORD ARCH
SWIFT CURRENT ARCH
DUPEROW EXTENT
BIRDBEAR EXTENT
MANITOBA
ALBERTA
SASKATCHEWAN
CORDILLERAN
THRUST FRONT
SWEETGRASS ARCH
E
A
CANADA
USA
WOLF CREEK NOSE
B
NESSON ANTICLINE
C
D
MIOGEOSYNCLINE
BILLINGS NOSE
CEDAR CREEK ANTICLINE
NORTH DAKOTA
MONTANA
BIRDBEAR EXTENT
DUPEROW EXTENT
IDAHO
WYOMING
SOUTH DAKOTA

Fig. 1 - Distribution of the Duperow and Birdbear (Nisku) Formations and equivalent formations. Major paleogeographic and structural elements and the positions of cross sections are shown.

(anhydrite) deposition, accompanied by progressive increase of reducing conditions in the lower part of the density-stratified water column. The laminated anhydrite unit diminishes in thickness and disappears in the southern portion of the Williston Basin, possibly reflecting dilution by near-shore fresh water runoff or, more likely, increased inhibition of calcium sulfate deposition by highly reducing bottom water concentrated in these more remote parts of the shelf. The latter interpretation is supported by the presence of thicker laminated anhydrite units and the progressive disappearance of the overlying pyritic, shaly mudstone units northwestward into Saskatchewan and Alberta (Kent, 1968; Dunn, 1975). Despite regional changes, these cycles are dominantly of subtidal origin and represent persistent, readily correlatable marker beds covering much of the shelf.

As a result of their relationship to identifiably shelf-wide events, these marker beds provide the means for reliable, approximately time-equivalent correlation of the carbonate facies and associated reservoir zones they bound. Utilization of four such markers within the Duperow, including the "Ireton" marker of the uppermost Duperow, allows for subdivision of the formation into five stratigraphic units, designated Unit 1 through Unit 5 from top to bottom (Fig. 4). The Birdbear Formation represents a sixth similar stratigraphic unit. The selection of unit-defining marker beds from among the numerous gamma-ray and anhydrite markers in this sequence is critical for proper assessment of facies and reservoir distribution. Depositional compensation can easily mask subtle thickness anomalies often associated with stromatoporoid-coral banks and biostromes. Over large portions of the northern Williston Basin influenced by multistage salt solution during the Late Devonian, depositional compensation is carried to an extreme with resulting thickness variations superimposed upon irregularities reflecting local bank development. This is particularly significant insofar as dolomitization of bank facies results in the most important reservoir type within both formations. Such reservoirs account for most Duperow fields along the Billings Nose in western North Dakota (Longman, 1982), for most Birdbear fields on the Wolf Creek Nose in northeastern Montana (Swenson, 1967; Ehrets and Kissling, 1983), as well as for recent Birdbear (Nisku) production established in the Sweetgrass Arch region of northwestern Montana. Moreover, because of the tendency for bank or biostrome development to be confined largely to predictable stratigraphic intervals (Fig. 5), the stratigraphic and facies concepts founded on the depositional models serves to more accurately predict areal extent of associated porosity zones. Utility of this stratigraphic scheme is particularly strong in those areas where definable paleogeographic features locally controlled deposition.

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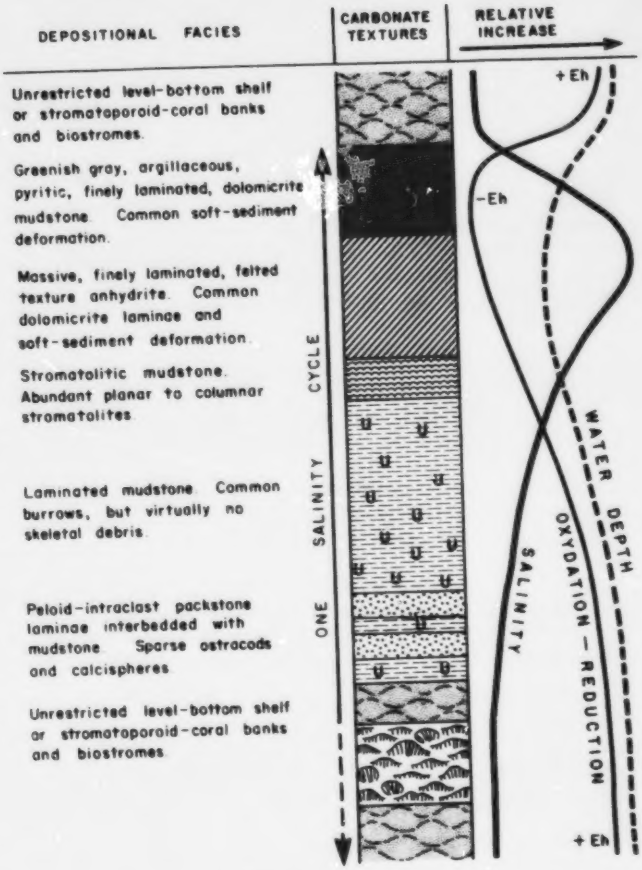
DEPOSITIONAL FACIES
CARBONATE TEXTURES
RELATIVE INCREASE
Unrestricted level-bottom shelf or stromatoporoid-coral banks and biostromes.
Greenish gray, argillaceous, pyritic, finely laminated, dolomicrite mudstone. Common soft-sediment deformation.
Massive, finely laminated, felted texture anhydrite. Common dolomicrite laminae and soft-sediment deformation.
Stromatolitic mudstone. Abundant planar to columnar stromatolites.
Laminated mudstone. Common burrows, but virtually no skeletal debris.
Peloid-intraclast packstone laminae interbedded with mudstone. Sparse ostracods and calcispheres.
Unrestricted level-bottom shelf or stromatoporoid-coral banks and biostromes.
ONE SALINITY CYCLE
+Eh
-Eh
+Eh
WATER DEPTH
OXYDATION – REDUCTION
SALINITY

Fig. 3 - Modeled vertical facies sequence for a single salinity cycle, with hypothetical relative salinity, water depth and oxidation-reduction potential curves.

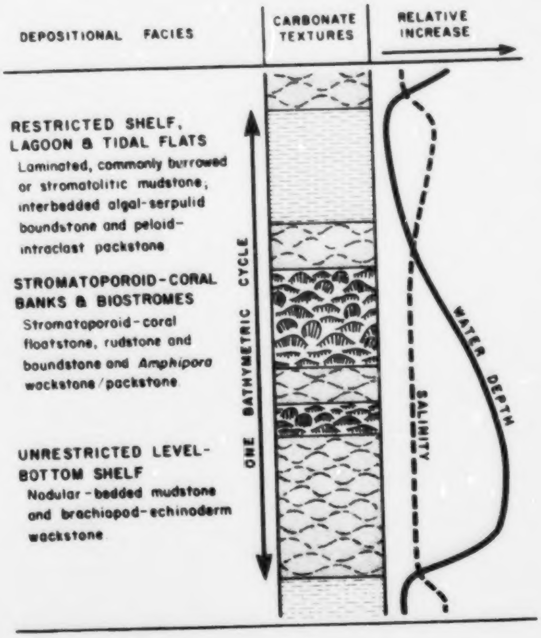
DEPOSITIONAL FACIES
CARBONATE TEXTURES
RELATIVE INCREASE
RESTRICTED SHELF, LAGOON & TIDAL FLATS
Laminated, commonly burrowed or stromatolitic mudstone, interbedded algal-serpulid boundstone and peloid-intraclast packstone
STROMATOPOROID-CORAL BANKS & BIOSTROMES
Stromatoporoid-coral floatstone, rudstone and boundstone and Amphipora wackstone/packstone
UNRESTRICTED LEVEL-BOTTOM SHELF
Nodular-bedded mudstone and brachiopod-echinoderm wackstone
ONE BATHYMETRIC CYCLE
WATER DEPTH
SALINITY

Fig. 2 - Modeled vertical facies sequence for a single carbonate cycle, with hypothetical relative salinity and water depth curves.

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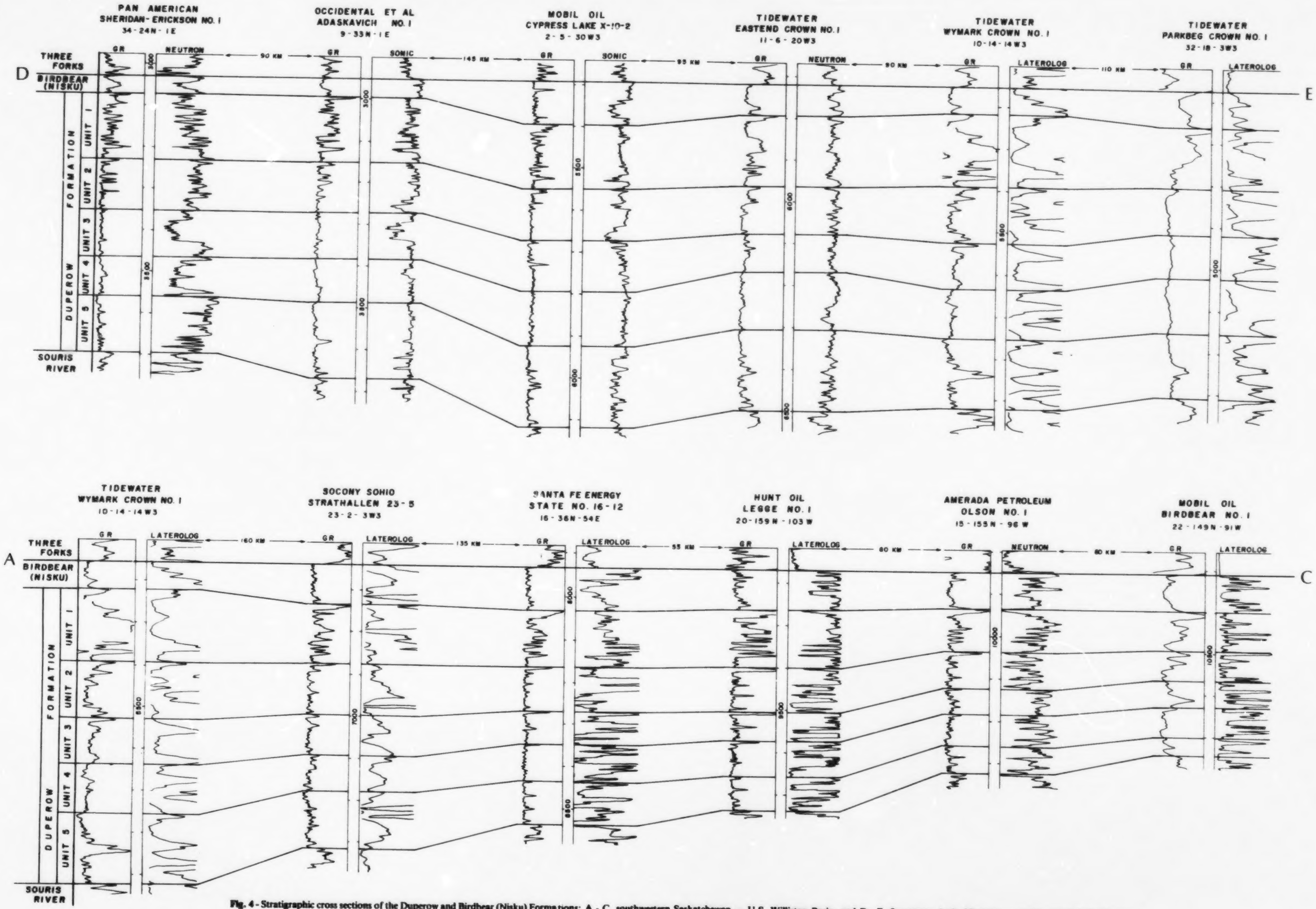

D
E
THREE FORKS
BIRDBEAR (NISKU)
DUPEROW FORMATION
UNIT 1
UNIT 2
UNIT 3
UNIT 4
UNIT 5
SOURIS RIVER
PAN AMERICAN SHERIDAN-ERICKSON NO. 1
34-24N-1E
GR
NEUTRON
90 KM
OCCIDENTAL ET AL ADASKAVICH NO. 1
9-33N-1E
GR
SONIC
145 KM
MOBIL OIL CYPRESS LAKE X-10-2
2-5-30W3
GR
SONIC
95 KM
TIDEWATER EASTEND CROWN NO. 1
11-6-20W3
GR
NEUTRON
90 KM
TIDEWATER WYMARK CROWN NO. 1
10-14-14W3
GR
LATEROLOG
110 KM
TIDEWATER PARKBEG CROWN NO. 1
32-18-3W3
GR
LATEROLOG
A
C
TIDEWATER WYMARK CROWN NO. 1
10-14-14W3
GR
LATEROLOG
160 KM
SOCONY SOHIO STRATHALLEN 23-5
23-2-3W3
GR
LATEROLOG
135 KM
SANTA FE ENERGY STATE NO. 16-12
16-36N-54E
GR
LATEROLOG
55 KM
HUNT OIL LEGGE NO. 1
20-159N-103W
GR
LATEROLOG
80 KM
AMERADA PETROLEUM OLSON NO. 1
15-155N-96W
GR
NEUTRON
80 KM
MOBIL OIL BIRDBEAR NO. 1
22-149N-91W
GR
LATEROLOG

Fig. 4 - Stratigraphic cross sections of the Duperow and Birdbear (Nisku) Formations: A - C, southwestern Saskatchewan — U.S. Williston Basin; and D - E, Sweetgrass Arch, Montana — south-central Saskatchewan.

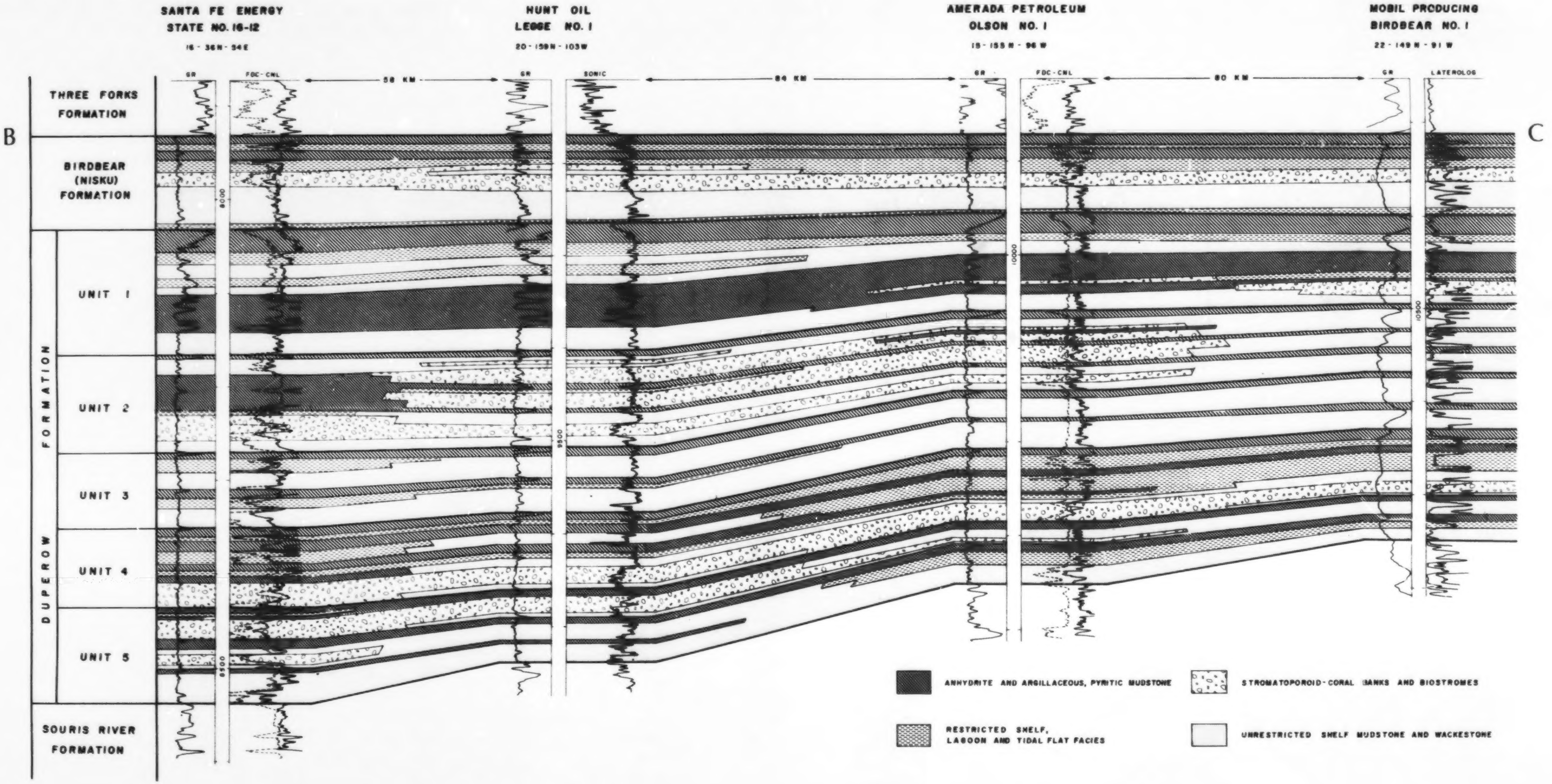
SANTA FE ENERGY
STATE NO. 16-12
16 - 36N - 54E
HUNT OIL
LEGGE NO. 1
20 - 159N - 103W
AMERADA PETROLEUM
OLSON NO. 1
15 - 155 N - 96 W
MOBIL PRODUCING
BIRDBEAR NO. 1
22 - 149 N - 91 W
GR
FDC - CNL
58 KM
GR
SONIC
84 KM
GR
FDC - CNL
80 KM
GR
LATEROLOG
B
C
THREE FORKS FORMATION
BIRDBEAR (NISKU) FORMATION
DUPEROW FORMATION
UNIT 1
UNIT 2
UNIT 3
UNIT 4
UNIT 5
SOURIS RIVER FORMATION
8000
8500
9500
10000
10500
ANHYDRITE AND ARGILLACEOUS, PYRITIC MUDSTONE
STROMATOPOROID - CORAL BANKS AND BIOSTROMES
RESTRICTED SHELF, LAGOON AND TIDAL FLAT FACIES
UNRESTRICTED SHELF MUDSTONE AND WACKESTONE

Fig. 5 - Stratigraphic and facies cross section B - C (U.S. Williston Basin) of the Duperow and Birdbear (Nisku) Formations. Lateral continuity of carbonate facies, as illustrated, does not imply actual facies continuity.